

THIS FILING IS

Item 1: An Initial (Original) Submission OR Resubmission No. _____

Form 1 Approved
OMB No. 1902-0021
(Expires 12/31/2011)
Form 1-F Approved
OMB No. 1902-0029
(Expires 12/31/2011)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 1/31/2012)



FERC FINANCIAL REPORT

FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)

Kansas City Power & Light Company

Year/Period of Report

End of 2010/Q4

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q) is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

- (1) one million megawatt hours of total annual sales,
- (2) 100 megawatt hours of annual sales for resale,
- (3) 500 megawatt hours of annual power exchanges delivered, or
- (4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: <http://www.ferc.gov/docs-filing/eforms/form-1/elec-subm-soft.asp>. The software is used to submit the electronic filing to the Commission via the Internet.

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

(d) For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

- a) Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and
- b) Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

<u>Reference Schedules</u>	<u>Pages</u>
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

- e) The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of _____ for the year ended on which we have reported separately under date of _____, we have also reviewed schedules _____ of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases."

The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

- (f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at <http://www.ferc.gov/help/how-to.asp>.

- (g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from <http://www.ferc.gov/docs-filing/eforms/form-1/form-1.pdf> and <http://www.ferc.gov/docs-filing/eforms.asp#3Q-gas>.

IV. When to Submit:

FERC Forms 1 and 3-Q must be filed by the following schedule:

- a) FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and
- b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,144 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 150 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

- I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.
- II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.
- III. Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.
- IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.
- V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions** (see VII. below).
- VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.
- VII. For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.
- VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.
- IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the

termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

(3) 'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

(4) 'Person' means an individual or a corporation;

(5) 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power;

(11) "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

(a) To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development -costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports salt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be filed..."

General Penalties

The Commission may assess up to \$1 million per day per violation of its rules and regulations. *See* FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Kansas City Power & Light Company		02 Year/Period of Report End of <u>2010/Q4</u>
03 Previous Name and Date of Change <i>(if name changed during year)</i> / /		
04 Address of Principal Office at End of Period <i>(Street, City, State, Zip Code)</i> 1200 Main, Kansas City, Missouri 64105		
05 Name of Contact Person Lori A. Wright		06 Title of Contact Person Vice President & Controller
07 Address of Contact Person <i>(Street, City, State, Zip Code)</i> 1200 Main, Kansas City, Missouri 64105		
08 Telephone of Contact Person, <i>Including Area Code</i> (816) 556-2200	09 This Report Is (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	10 Date of Report <i>(Mo, Da, Yr)</i> 04/15/2011

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name Lori A. Wright	03 Signature Lori A. Wright	04 Date Signed <i>(Mo, Da, Yr)</i> 04/15/2011
02 Title Vice President & Controller		

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	None
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	
24	Extraordinary Property Losses	230	None
25	Unrecovered Plant and Regulatory Study Costs	230	None
26	Transmission Service and Generation Interconnection Study Costs	231	None
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	None
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	None
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Sales of Electricity by Rate Schedules	304	
44	Sales for Resale	310-311	
45	Electric Operation and Maintenance Expenses	320-323	
46	Purchased Power	326-327	
47	Transmission of Electricity for Others	328-330	
48	Transmission of Electricity by ISO/RTOs	331	Not Applicable
49	Transmission of Electricity by Others	332	
50	Miscellaneous General Expenses-Electric	335	
51	Depreciation and Amortization of Electric Plant	336-337	
52	Regulatory Commission Expenses	350-351	
53	Research, Development and Demonstration Activities	352-353	
54	Distribution of Salaries and Wages	354-355	
55	Common Utility Plant and Expenses	356	None
56	Amounts included in ISO/RTO Settlement Statements	397	
57	Purchase and Sale of Ancillary Services	398	
58	Monthly Transmission System Peak Load	400	
59	Monthly ISO/RTO Transmission System Peak Load	400a	Not Applicable
60	Electric Energy Account	401	
61	Monthly Peaks and Output	401	
62	Steam Electric Generating Plant Statistics	402-403	
63	Hydroelectric Generating Plant Statistics	406-407	None
64	Pumped Storage Generating Plant Statistics	408-409	None
65	Generating Plant Statistics Pages	410-411	
66	Transmission Line Statistics Pages	422-423	

Name of Respondent
Kansas City Power & Light Company

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
04/15/2011

Year/Period of Report
End of 2010/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Lines Added During the Year	424-425	
68	Substations	426-427	
69	Transactions with Associated (Affiliated) Companies	429	
70	Footnote Data	450	

Stockholders' Reports Check appropriate box:

- Two copies will be submitted
- No annual report to stockholders is prepared

Name of Respondent Kansas City Power & Light Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of <u>2010/Q4</u>
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GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Lori Wright, Vice President & Controller
1200 Main Street
Kansas City, Missouri 64105

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

Incorporated - State of Missouri, July 29, 1922

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

N/A

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Missouri - Electric
Kansas - Electric

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

- (1) Yes...Enter the date when such independent accountant was initially engaged:
(2) No

Name of Respondent Kansas City Power & Light Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of <u>2010/Q4</u>
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CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the respondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiaries for whom trust was maintained, and purpose of the trust.

The above required information is available from the below referenced SEC 10-K report Form filing for the fiscal year ending December 31, 2010:

Commission File Number	Registrant, State of Incorporation Address and Telephone Number	I.R.S. Employer Identification Number
001-32206	GREAT PLAINS ENERGY INCORPORATED (A Missouri Corporation) 1200 Main Street Kansas City, Missouri 64105 (816) 556-2200	43-1916803
000-51873	KANSAS CITY POWER & LIGHT COMPANY (A Missouri Corporation) 1200 Main Street Kansas City, Missouri 64105 (816) 556-2200	44-0308720

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions

1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Wolf Creek Nuclear Operating Corporation	Operating agent for Wolf	47%	
2		Creek Generating Station		
3				
4	Kansas City Power & Light Receivables Company	Corporation that purchases	100%	
5		customer receivables from		
6		KCP&L and sells to outside		
7		investors.		
8				
9	KCP&L, Inc. (Kansas)	Inactive	100%	
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11	KCP&L, Inc. (Missouri)	Inactive	100%	
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Name of Respondent Kansas City Power & Light Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Schedule Page: 103 Line No.: 1 Column: d
Owned and controlled jointly with Kansas Gas and Electric 47% and Kansas Electric Power Co-operative 6%.

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is \$50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
 2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	Chairman of the Board and Chief Executive Officer	Michael J. Chesser	800,000
2			
3			
4	President and Chief Operating Officer	William H. Downey	510,000
5			
6			
7	Executive Vice President - Utility Operations and former Chief Financial Officer	Terry Bassham	430,000
8			
9			
10			
11	Senior Vice President - Supply	Scott H. Heidtbrink	267,000
12			
13			
14	Senior Vice President - Delivery	Michael L. Deggendorf	260,000
15			
16			
17	Senior Vice President - Finance and Strategic Development and Chief Financial Officer (beginning July 2010)	James C. Shay	183,634
18			
19			
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21			
22	Former Executive Vice President - Utility Operations (Retired July 2010)	John R. Marshall	250,000
23			
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25			
26	Former General Counsel and Chief Legal Officer (Resigned October 2010)	William G. Riggins	230,398
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DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Dr. David L. Bodde	Senior Fellow & Professor
2		Arthur M. Spiro Center for Entrepreneurial Leadership
3		Clemson University
4		346 Surrine Hall
5		Clemson, SC 29634-1345
6		
7	William C. Nelson	Chairman
8		George K. Baum Asset Management
9		4801 Main St., Suite 500
10		Kansas City, MO 64112
11		
12	Dr. Linda Hood Talbott	President and CEO
13		Talbott & Associates
14		P.O. Box 22322
15		Kansas City, MO 64113-3022
16		
17	Randall C. Ferguson, Jr.	c/o Great Plains Energy
18		1200 Main Street
19		P.O. Box 418679
20		Kansas City, MO 64141-9679
21		
22	James A. Mitchell	Executive Fellow - Leadership
23		Center for Ethical Business Cultures
24		1000 LaSalle Avenue MJH-300
25		Minneapolis, MN 55403-2005
26		
27	Robert H. West	c/o Great Plains Energy
28		1200 Main Street
29		P.O. Box 418679
30		Kansas City, MO 64141-9679
31		
32	Gary D. Forsee	c/o Great Plains Energy
33		1200 Main Street
34		P.O. Box 418679
35		Kansas City, MO 64141-9679
36		
37	John J. Sherman	President and Chief Executive Officer
38		Inergy, L.P.
39		2 Brush Creek Blvd, Ste 200
40		Kansas City, MO 64112
41		
42	Michael J. Chesser	1200 Main Street
43	Chairman of the Board and Chief Executive Officer	P.O. Box 418679
44		Kansas City, MO 64141-9679
45		
46	William H. Downey	1200 Main Street
47	President and Chief Operating Officer	P.O. Box 418679
48		Kansas City, MO 64141-9679

Name of Respondent
Kansas City Power & Light Company

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
04/15/2011

Year/Period of Report
End of 2010/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates?

Yes
 No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	Transmission Formula Rate (TFR)	ER10-230-000
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Name of Respondent
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INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?

Yes
 No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
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INFORMATION ON FORMULA RATES
 Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s).	Schedule	Column	Line No
1		Additional detail has been provided in footnotes		
2		on various FERC Form 1 pages for use in the		
3		FERC formula rate, Docket No. ER10-230-000.		
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Name of Respondent Kansas City Power & Light Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report 04/15/2011	Year/Period of Report End of <u>2010/Q4</u>
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IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 106, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report 2010/Q4
Kansas City Power & Light Company			
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

1. Franchises renewed during 2010 are as follows:

<u>Utility</u>	<u>Town</u>	<u>State</u>	<u>Term</u>	<u>Action</u>	<u>Consideration</u>	
Electric	Merriam	KS	10 years	Renewal	5.00%	Effective 1/1/2010
Electric	Bonner Springs	KS	10 years	Renewal	6.00%	Effective 2/1/2010
Electric	Westwood Hills	KS	15 years	Renewal	5.00%	Effective 5/1/2010
Electric	Sedalia	MO	20 years	Renewal	5.00%	Effective 6/1/2010
Electric	Mission Woods	KS	15 years	Renewal	5.00%	Effective 12/1/2010
Electric	Mission Hills	KS	10 years	Renewal	5.00%	Effective 12/1/2010

2. None

3. None

4. None

5. None

6. Please see pages 122-123 for Notes to Financial Statements, Note 10 Short-Term Borrowings and Short-Term Bank Lines of Credit and Note 11 Long-Term Debt for obligations incurred during 2010.

7. None

8. Management and general contract (union) wage increases during 2010 are as follows:

Local 1464 increase of 3.50% was effective 2/1/2010.

Local 412 increase of 3.40% was effective 3/1/2010.

KCP&L management merit increase of 3.00% was effective 3/1/2010.

Local 1613 increase of 3.25% was effective 4/1/2010.

9. **Legal and Regulatory Proceedings/Actions:**

Please see pages 122-123 for Notes to Financial Statements, Note 5 Regulatory Matters, Note 13 Commitments and Contingencies detailing 2010 Environmental Matters and Note 14 for Legal Proceedings that were still active at December 31, 2010.

10. See 13.

11. Reserved

12. See the Notes to Financial Statements included on pages 122-123.

13. On January 2, 2010, Lora Cheatum resigned as Vice President - Procurement.

On January 2, 2010, Maria Jenks became Vice President - Supply Chain.

On May 4, 2010, Dana Crawford's title changed from Vice President - Strategic Operations Support to Vice President - Strategic Initiatives.

On May 6, 2010, Great Plains Energy announced that John M. Marshall, Executive Vice President - Utility Operations of KCP&L, and Barbara B. Curry, Senior Vice President - Human Resources and Corporate Secretary of Great Plains Energy, KCP&L and GMO, would be retiring on July 31, 2010, and May 31, 2010, respectively.

On May 4, 2010, the Boards of Directors of Great Plains Energy, KCP&L and GMO approved retirement and consulting agreements for Mr. Marshall and Ms. Curry. Each executive's agreement provides for, among other things: (a) the

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Kansas City Power & Light Company			
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

forfeiture as of the applicable retirement date of restricted stock and performance share grants made in 2010 to the executive; (b) the vesting and payment of restricted stock and performance share grants made prior to 2010 to the executive as though the executive continued his or her employment through the applicable vesting and payment dates; (c) the payment of the executive's 2010 annual incentive plan award as though the executive continued his or her employment through December 31, 2010, with the executive deemed to have achieved the target level of the individual performance component of the award; (d) a consulting arrangement through December 31, 2010, in consideration of a \$100,000 lump sum payment; and (e) a general cross-release of claims. In addition, Mr. Marshall's agreement provides for a special bonus of \$240,000, payable upon his retirement. Mr. Marshall's position changed to Executive Vice President of KCP&L and GMO effective as of July 6, 2010, and on July 31, 2010, he retired.

On May 4, 2010, Terry Bassham was appointed Executive Vice President – Utility Operations of KCP&L and GMO, effective as of July 6, 2010. Until this appointment became effective, Mr. Bassham continued in his positions as Executive Vice President – Finance and Strategic Planning and Chief Financial Officer of Great Plains Energy, KCP&L and GMO. There were no changes made to Mr. Bassham's existing compensation arrangements.

Also on May 4, 2010, the Boards of Directors of Great Plains Energy, KCP&L and GMO appointed James C. Shay as Senior Vice President – Finance and Strategic Planning and Chief Financial Officer, effective as of July 6, 2010. Mr. Shay's annual salary will be \$375,000, subject to adjustment from time to time by the Board of Directors. He will receive a \$500,000 grant of time-based restricted stock, 60% of which will vest in three years, 20% will vest in four years, and 20% will vest in five years from the date of grant, which is expected to occur in August 2010. Mr. Shay's target amount of incentive compensation under Great Plains Energy's annual incentive plan is set at 60%, with any payment for 2010 prorated for the time Mr. Shay was an officer that year. Mr. Shay will also be eligible to receive, starting in 2011, equity grants under Great Plains Energy's long-term incentive plan equal, at target performance, to 100% of his base salary. Mr. Shay is expected to enter into customary indemnification and change in control severance agreements, and will participate in Great Plains Energy's qualified defined benefit pension plan and supplemental executive retirement plan on the same basis as Mr. Bassham, as described in Great Plains Energy's proxy statement filed with the Securities and Exchange Commission on March 24, 2010.

On May 18, 2010, Carl D. Churchman, Vice President - Construction of KCP&L and GMO, resigned his positions.

On June 1, 2010, Michael Cline's position changed from Vice President - Investor Relations and Treasurer to Vice President - Investor Relations, Treasurer and Corporate Secretary. On October 26, 2010, Michael Cline's position changed to Vice President - Investor Relations and Treasurer.

On June 1, 2010, Ellen Fairchild became Assistant Secretary and Senior Director - Investor Relations. On October 26, 2010, Ellen Fairchild's position changed to Vice President, Corporate Secretary and Chief Compliance Officer.

On October 7, 2010, William Riggins, General Counsel and Chief Legal Officer, resigned his position.

On October 7, 2010, Heather Humphrey became Interim General Counsel and Senior Director - Human Resources and on October 26, 2010, she became General Counsel and Vice President - Human Resources.

14. Not Applicable

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	UTILITY PLANT			
2	Utility Plant (101-106, 114)	200-201	7,540,925,935	6,258,514,423
3	Construction Work in Progress (107)	200-201	227,542,942	1,144,170,255
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		7,768,468,877	7,402,684,678
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	3,104,681,195	2,899,768,920
6	Net Utility Plant (Enter Total of line 4 less 5)		4,663,787,682	4,502,915,758
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202-203	8,831,886	12,190,208
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		39,537,985	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		78,870,218	78,870,218
10	Spent Nuclear Fuel (120.4)		83,085,759	83,085,759
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	131,093,239	105,975,785
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		79,232,609	68,170,400
14	Net Utility Plant (Enter Total of lines 6 and 13)		4,743,020,291	4,571,086,158
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	OTHER PROPERTY AND INVESTMENTS			
18	Nonutility Property (121)		8,988,611	4,584,195
19	(Less) Accum. Prov. for Depr. and Amort. (122)		4,528,545	2,102,385
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	7,111,324	3,779,947
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		1,786,664	3,241,798
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		129,179,248	112,487,043
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	0
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		142,537,302	121,990,598
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		2,311,354	1,516,320
36	Special Deposits (132-134)		401,797	73,723
37	Working Fund (135)		10,000	44,098
38	Temporary Cash Investments (136)		11,560	15,040,376
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		0	0
41	Other Accounts Receivable (143)		71,097,203	76,157,764
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		0	0
43	Notes Receivable from Associated Companies (145)		63,900,770	50,274,913
44	Accounts Receivable from Assoc. Companies (146)		30,827,697	36,516,694
45	Fuel Stock (151)	227	44,875,683	45,596,392
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	85,976,845	77,856,217
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	8,433,844	6,949,219
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		9,349,503	10,402,885
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		0	189,200
61	Accrued Utility Revenues (173)		0	0
62	Miscellaneous Current and Accrued Assets (174)		19,471,728	19,452,158
63	Derivative Instrument Assets (175)		0	0
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
65	Derivative Instrument Assets - Hedges (176)		0	242,000
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		336,667,984	340,311,959
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		19,785,436	17,137,558
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	771,119,608	722,643,301
73	Prelim. Survey and Investigation Charges (Electric) (183)		0	0
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		644,454	2,164,738
77	Temporary Facilities (185)		595	455
78	Miscellaneous Deferred Debits (186)	233	5,627,822	40,133,347
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	107,450	145,000
81	Unamortized Loss on Reaquired Debt (189)		5,029,032	5,311,425
82	Accumulated Deferred Income Taxes (190)	234	499,012,271	468,954,103
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,301,326,668	1,256,489,927
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		6,523,552,245	6,289,878,642

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	487,041,247	487,041,247
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		0	0
7	Other Paid-In Capital (208-211)	253	1,076,114,704	1,076,114,704
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	468,767,656	403,870,643
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	4,111,325	779,947
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-36,401,942	-41,533,850
16	Total Proprietary Capital (lines 2 through 15)		1,999,632,990	1,926,272,691
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,778,668,000	1,778,668,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	3,271,797	3,491,904
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		1,893,266	2,050,854
24	Total Long-Term Debt (lines 18 through 23)		1,780,046,531	1,780,109,050
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		2,049,939	2,106,928
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		3,008,311	2,319,441
29	Accumulated Provision for Pensions and Benefits (228.3)		407,316,715	421,180,541
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		129,729,039	119,846,415
35	Total Other Noncurrent Liabilities (lines 26 through 34)		542,104,004	545,453,325
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		263,500,000	186,577,000
38	Accounts Payable (232)		220,777,708	256,173,309
39	Notes Payable to Associated Companies (233)		1,960,000	4,306,020
40	Accounts Payable to Associated Companies (234)		0	585,606
41	Customer Deposits (235)		6,282,681	7,358,676
42	Taxes Accrued (236)	262-263	21,290,207	22,380,642
43	Interest Accrued (237)		26,216,879	26,722,311
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS) (Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		6,028,104	6,459,718
48	Miscellaneous Current and Accrued Liabilities (242)		25,584,242	41,912,453
49	Obligations Under Capital Leases-Current (243)		56,988	52,673
50	Derivative Instrument Liabilities (244)		0	0
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		571,696,809	552,528,408
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		1,855,709	2,096,403
57	Accumulated Deferred Investment Tax Credits (255)	266-267	129,361,188	135,680,838
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	50,934,361	51,179,209
60	Other Regulatory Liabilities (254)	278	246,374,487	250,721,276
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		1,032,281,747	907,112,328
64	Accum. Deferred Income Taxes-Other (283)		169,264,419	138,725,114
65	Total Deferred Credits (lines 56 through 64)		1,630,071,911	1,485,515,168
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		6,523,552,245	6,289,878,642

STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility column in a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	1,517,115,275	1,317,389,133		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	691,575,624	637,307,890		
5	Maintenance Expenses (402)	320-323	109,085,967	94,690,738		
6	Depreciation Expense (403)	336-337	170,793,850	158,448,413		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	1,077,334	1,237,923		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	85,449,365	71,153,577		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)					
13	(Less) Regulatory Credits (407.4)		8,966,859	8,590,216		
14	Taxes Other Than Income Taxes (408.1)	262-263	129,279,029	118,706,127		
15	Income Taxes - Federal (409.1)	262-263	8,324,281	47,799,793		
16	- Other (409.1)	262-263	1,750,978	5,211,540		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	83,474,901	-30,018,060		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	-4,286,870	7,982,717		
19	Investment Tax Credit Adj. - Net (411.4)	266	-6,288,806	35,851,252		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		7,889,525	7,352,293		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,277,732,059	1,131,168,553		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		239,383,216	186,220,580		

STATEMENT OF INCOME FOR THE YEAR (Continued)

- 9. Use page 122 for important notes regarding the statement of income for any account thereof.
- 10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
- 11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.
- 12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
- 13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
- 14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
- 15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		Line No.
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	
1,517,115,275	1,317,389,133					2
						3
691,575,624	637,307,890					4
109,085,967	94,690,738					5
170,793,850	158,448,413					6
1,077,334	1,237,923					7
85,449,365	71,153,577					8
						9
						10
						11
						12
8,966,859	8,590,216					13
129,279,029	118,706,127					14
8,324,281	47,799,793					15
1,750,978	5,211,540					16
83,474,901	-30,018,060					17
-4,286,870	7,982,717					18
-6,288,806	35,851,252					19
						20
						21
						22
						23
7,889,525	7,352,293					24
1,277,732,059	1,131,168,553					25
239,383,216	186,220,580					26

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL		Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
			Current Year (c)	Previous Year (d)		
27	Net Utility Operating Income (Carried forward from page 114)		239,383,216	186,220,580		
28	Other Income and Deductions					
29	Other Income					
30	Nonutility Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)		4,638,532	3,598,496		
34	(Less) Expenses of Nonutility Operations (417.1)		590,027	748,238		
35	Nonoperating Rental Income (418)		-83,832	27,067		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	3,331,378	3,318,809		
37	Interest and Dividend Income (419)		1,114,762	633,139		
38	Allowance for Other Funds Used During Construction (419.1)		21,882,306	30,631,196		
39	Miscellaneous Nonoperating Income (421)		676,842	1,450,929		
40	Gain on Disposition of Property (421.1)		52,941	122,324		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		31,022,902	39,033,722		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		184,018	170,059		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		2,307,718	1,461,668		
46	Life Insurance (426.2)		85,574	431,496		
47	Penalties (426.3)		13,477	969		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		772,491	687,712		
49	Other Deductions (426.5)		31,338,293	15,913,613		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		34,701,571	18,665,517		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	77,720	72,321		
53	Income Taxes-Federal (409.2)	262-263	-6,167,516	-5,082,064		
54	Income Taxes-Other (409.2)	262-263	-1,171,265	-957,569		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277				
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	4,653,846			
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)		30,844	30,844		
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-11,945,751	-5,998,156		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		8,267,082	26,366,361		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		117,899,084	110,350,933		
63	Amort. of Debt Disc. and Expense (428)		2,500,690	1,754,654		
64	Amortization of Loss on Reaquired Debt (428.1)		409,481	395,363		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		69,588	27,733		
68	Other Interest Expense (431)		-14,102,979	2,258,401		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		22,353,957	31,090,977		
70	Net Interest Charges (Total of lines 62 thru 69)		84,421,907	83,696,107		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		163,228,391	128,890,834		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		163,228,391	128,890,834		

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report 2010/Q4
Kansas City Power & Light Company			
FOOTNOTE DATA			

Schedule Page: 114 Line No.: 68 Column: c

Per Case No. ER10-230-000, FERC transmission formula rate case, additional detail for other interest expense has been provided below:

<u>Account</u>	<u>Description</u>	<u>Q1</u>	<u>Q2</u>	<u>Q3</u>	<u>Q4</u>	<u>Total</u>
431015	Commitment Exp-ST Loans	162,060	213,676	548,354	725,614	1,649,704
431016	Interest on Unsecured Notes	207,878	305,077	267,108	206,753	986,816
	All Other	(1,257,801)	(1,227,481)	(5,409,946)	(8,844,271)	(16,739,499)
	Total Other Interest Expense	(887,863)	(708,728)	(4,594,484)	(7,911,904)	(14,102,979)

Schedule Page: 114 Line No.: 68 Column: d

Per Docket No. ER10-230-000, FERC transmission formula rate, additional detail for other interest expense has been provided below:

<u>Account</u>	<u>Description</u>	<u>Q1</u>	<u>Q2</u>	<u>Q3</u>	<u>Q4</u>	<u>Total</u>
431015	Commitment Exp-ST Loans	235,811	179,166	153,455	155,714	724,146
431016	Interest on Unsecured Notes	2,233,654	883,482	103,858	115,121	3,336,115
	All Other	29,301	(110,942)	(775,935)	(944,284)	(1,801,860)
	Total Other Interest Expense	2,498,766	951,706	(518,622)	(673,449)	2,258,401

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		403,870,643	396,449,640
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		159,897,013	125,572,025
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31			-95,000,000	(72,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-95,000,000	(72,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			(46,151,022)
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		468,767,656	403,870,643
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		468,767,656	403,870,643
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		779,947	(48,689,883)
50	Equity in Earnings for Year (Credit) (Account 418.1)		3,331,378	3,318,809
51	(Less) Dividends Received (Debit)			
52	Transfer of earnings to appropriate retained earnings account			46,151,021
53	Balance-End of Year (Total lines 49 thru 52)		4,111,325	779,947

Name of Respondent Kansas City Power & Light Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Schedule Page: 118 Line No.: 52 Column: d

The transfer of earnings to the appropriate retained earnings account consists of the following components:

\$48,831,955	to reflect transfer of KCP&L's investment in HSS, Inc. to KLT, Inc.
(\$2,717,550)	to reflect subsidiary income from KCREC
<u>\$36,617</u>	to adjust for miscellaneous difference between KCP&L and KCREC
\$46,151,022	

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.

(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.

(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.

(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	163,228,391	128,890,834
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	256,243,215	229,601,990
5	Amortization of		
6	Nuclear fuel	25,117,453	16,113,084
7	Other	10,998,266	9,049,705
8	Deferred Income Taxes (Net)	83,107,925	-38,000,777
9	Investment Tax Credit Adjustment (Net)	-6,319,650	35,820,408
10	Net (Increase) Decrease in Receivables	-8,262,425	27,362,574
11	Net (Increase) Decrease in Inventory	-8,884,544	-10,470,450
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-3,673,542	-47,316,077
14	Net (Increase) Decrease in Other Regulatory Assets	-34,887,296	-21,924,925
15	Net Increase (Decrease) in Other Regulatory Liabilities	3,185,882	493,241
16	(Less) Allowance for Other Funds Used During Construction	21,882,306	30,631,196
17	(Less) Undistributed Earnings from Subsidiary Companies	3,331,378	3,318,809
18	Other (provide details in footnote):	62,155,620	-8,376,137
19			
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	516,795,611	287,293,465
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-471,173,098	-667,846,311
27	Gross Additions to Nuclear Fuel	-36,179,663	-20,412,857
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-175,937	-206,492
30	(Less) Allowance for Other Funds Used During Construction	-21,882,306	-30,631,196
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-485,646,392	-657,834,464
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)	-83,270,939	-99,014,359
45	Proceeds from Sales of Investment Securities (a)	79,597,213	95,340,635

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
 (2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
 (3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
 (4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
54	Salvage and removal	-13,351,458	-400,191
55	Net money pool lending	-6,075,000	-6,000,000
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-508,746,576	-667,908,379
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		413,176,406
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65	Net money pool borrowings	1,098,258	861,742
66	Net Increase in Short-Term Debt (c)	76,923,000	
67	Other (provide details in footnote):		
68	Contributions from Great Plains Energy		247,500,000
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	78,021,258	661,538,148
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-220,106	
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Issuance costs	-5,118,067	-4,032,839
78	Net Decrease in Short-Term Debt (c)		-193,587,000
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-95,000,000	-72,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-22,316,915	391,918,309
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-14,267,880	11,303,395
87			
88	Cash and Cash Equivalents at Beginning of Period	16,600,794	5,297,399
89			
90	Cash and Cash Equivalents at End of period	2,332,914	16,600,794

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report 2010/Q4
Kansas City Power & Light Company			
FOOTNOTE DATA			

Schedule Page: 120 Line No.: 90 Column: b

	<u>2010</u>	<u>2009</u>
Balance Sheet, pages 110-111:		
Line No. 35 - Cash (131)	\$2,311,354	\$ 1,516,320
Line No. 36 - Special Deposits (132-134)	401,797	73,723
Line No. 37 - Working Fund (135)	10,000	44,098
Line No. 38 - Temporary Cash Investments (136)	11,560	15,040,376
Total Balance Sheet	\$2,734,711	\$16,674,517
Less: Funds on Deposit in 134, not considered		
Cash and Cash Equivalents	(401,797)	(73,723)
Cash and Cash Equivalents at End of Period	\$2,332,914	\$16,600,794

Name of Respondent Kansas City Power & Light Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report 04/15/2011	Year/Period of Report End of <u>2010/Q4</u>
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NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

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SEE PAGE 123 FOR REQUIRED INFORMATION.

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KANSAS CITY POWER & LIGHT COMPANY

Notes to Financial Statements

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization

The terms "Company" and "KCP&L" are used throughout this report and refer to Kansas City Power & Light Company. KCP&L is an integrated, regulated electric utility that provides electricity to customers primarily in the states of Missouri and Kansas. KCP&L is a wholly owned subsidiary of Great Plains Energy Incorporated (Great Plains Energy). Great Plains Energy also owns KCP&L Greater Missouri Operations Company (GMO), a regulated electric utility.

Basis of Accounting

The accounting records of Kansas City Power & Light Company (KCP&L) are maintained in accordance with the accounting requirements of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts and published accounting releases. The accompanying financial statements have been prepared in accordance with the accounting requirements of these regulators, which differ from Generally Accepted Accounting Principles (GAAP). KCP&L classifies certain items in its accompanying Comparative Balance Sheet (primarily the components of accumulated deferred income taxes, certain miscellaneous current and accrued liabilities and current maturities of long-term debt) in a manner different than that required by GAAP. In addition, in accordance with regulatory reporting requirements, KCP&L accounts for its investments in majority-owned subsidiaries on the equity method rather than consolidating the assets, liabilities, revenues and expenses of these subsidiaries, as required by GAAP.

Use of Estimates

The process of preparing financial statements requires the use of estimates and assumptions that affect the reported amounts of certain types of assets, liabilities, revenues, and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements. Accordingly, upon settlement, actual results may differ from estimated amounts.

Cash and Cash Equivalents

Cash equivalents consist of highly liquid investments with original maturities of three months or less at acquisition.

Funds on Deposit

Funds on deposit consist primarily of cash provided to counterparties in support of margin requirements related to commodity purchases, commodity swaps and futures contracts. Pursuant to individual contract terms with counterparties, deposit amounts required vary with changes in market prices, credit provisions and various other factors. Interest is earned on most funds on deposit.

Fair Value of Financial Instruments

The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate that value.

Nuclear decommissioning trust fund – KCP&L's nuclear decommissioning trust fund assets are recorded at fair value. Fair value is based on quoted market prices of the investments held by the fund and/or valuation models.

Long-term debt – Fair value is based on quoted market prices, with the incremental borrowing rate for similar debt used to determine fair value if quoted market prices were not available. At December 31, 2010, the book value and fair value of KCP&L's long-term debt, including current maturities, was \$1.8 billion and \$1.9 billion, respectively. At December 31, 2009, the book value and fair value of KCP&L's long-term debt, including current maturities, was \$1.8 billion and

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\$1.9 billion, respectively.

Derivative instruments – The fair value of derivative instruments is estimated using market quotes, over-the-counter forward price and volatility curves and correlation among fuel prices, net of estimated credit risk.

Pension plans – For financial reporting purposes, the market value of plan assets is the fair value. KCP&L uses a five-year smoothing of assets to determine fair value for regulatory reporting purposes.

Derivative Instruments

The Company records derivative instruments on the balance sheet at fair value in accordance with GAAP. The Company enters into derivative contracts to manage exposure to commodity price and interest rate fluctuations. Derivative instruments designated as normal purchases and normal sales (NPNS) and cash flow hedges are used solely for hedging purposes and are not issued or held for speculative reasons.

The Company considers various qualitative factors, such as contract and market place attributes, in designating derivative instruments at inception. The Company may elect the NPNS exception, which requires the effects of the derivative to be recorded when the underlying contract settles. The Company accounts for derivative instruments that are not designated as NPNS as cash flow hedges or non-hedging derivatives, which are recorded as assets or liabilities on the balance sheet at fair value. In addition, if a derivative instrument is designated as a cash flow hedge, the Company documents the method of determining hedge effectiveness and measuring ineffectiveness. See Note 16 for additional information regarding derivative financial instruments and hedging activities.

The Company offsets fair value amounts recognized for derivative instruments under master netting arrangements, which include rights to reclaim cash collateral (a receivable), or the obligation to return cash collateral (a payable). The Company classifies cash flows from derivative instruments in the same category as the cash flows from the items being hedged.

Utility Plant

KCP&L's utility plant is stated at historical cost. These costs include taxes, an allowance for the cost of borrowed and equity funds used to finance construction and payroll-related costs, including pensions and other fringe benefits. Replacements, improvements and additions to units of property are capitalized. Repairs of property and replacements of items not considered to be units of property are expensed as incurred (except as discussed under Deferred Refueling Outage Costs). When property units are retired or otherwise disposed, the original cost, net of salvage, is charged to accumulated depreciation. Substantially all of KCP&L's utility plant is pledged as collateral for KCP&L's mortgage bonds under the General Mortgage Indenture and Deed of Trust dated December 1, 1986, as supplemented.

As prescribed by FERC, Allowance for Funds Used During Construction (AFUDC) is charged to the cost of the plant during construction. AFUDC equity funds are included as a non-cash item in non-operating income and AFUDC borrowed funds are a reduction of interest charges. The rates used to compute gross AFUDC are compounded semi-annually and averaged 6.8% in 2010 and 7.6% in 2009.

Utility plant includes production (20- to 60-year life), transmission (15- to 70-year life), distribution (8- to 55-year life) and general equipment (5- to 50-year life) and is recorded at original cost, net of accumulated depreciation.

Depreciation and Amortization

Depreciation and amortization of KCP&L's utility plant other than nuclear fuel is computed using the straight-line method over the estimated lives of depreciable property based on rates approved by state regulatory authorities. Annual depreciation rates average approximately 3%. Nuclear fuel is amortized to fuel expense based on the quantity of heat

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produced during the generation of electricity.

KCP&L's depreciation expense was \$170.8 million and \$158.4 million for 2010 and 2009, respectively. KCP&L's depreciation and amortization expense includes \$72.6 million and \$58.2 million for 2010 and 2009, respectively, of additional amortization to help maintain cash flow levels during KCP&L's Comprehensive Energy Plan pursuant to orders of the Public Service Commission of the State of Missouri (MPSC) and The State Corporation Commission of the State of Kansas (KCC).

Nuclear Plant Decommissioning Costs

Nuclear plant decommissioning cost estimates are based on the immediate dismantlement method and include the costs of decontamination, dismantlement and site restoration. Based on these cost estimates, KCP&L contributes to a tax-qualified trust fund to be used to decommission Wolf Creek Generating Station (Wolf Creek). Related liabilities for decommissioning are included on KCP&L's balance sheet in Asset Retirement Obligations (AROs).

As a result of the authorized regulatory treatment and related regulatory accounting, differences between the decommissioning trust fund asset and the related ARO are recorded as a regulatory asset or liability. See Note 7 for discussion of AROs including those associated with nuclear plant decommissioning costs.

Deferred Refueling Outage Costs

KCP&L uses the deferral method to account for operations and maintenance expenses incurred in support of Wolf Creek's scheduled refueling outages and amortizes them evenly (monthly) over the unit's operating cycle of 18 months until the next scheduled outage. Replacement power costs during an outage are expensed as incurred.

Regulatory Matters

KCP&L defers items on the balance sheet resulting from the effects of the ratemaking process, which would not be recorded if KCP&L was not regulated. See Note 5 for additional information concerning regulatory matters.

Revenue Recognition

KCP&L recognizes revenues on sales of electricity when the service is provided. Revenues recorded include electric services provided but not yet billed by KCP&L. Unbilled revenues are recorded for kWh usage in the period following the customers' billing cycle to the end of the month. KCP&L's estimate is based on net system kWh usage less actual billed kWhs. KCP&L's estimated unbilled kWhs are allocated and priced by regulatory jurisdiction across the rate classes based on actual billing rates.

KCP&L collects from customers gross receipts taxes levied by state and local governments. These taxes from KCP&L's Missouri customers are recorded gross in operating revenues and general taxes on KCP&L's statement of income. KCP&L's gross receipts taxes collected from Missouri customers were \$54.3 million and \$46.8 million in 2010 and 2009, respectively. These taxes from KCP&L's Kansas customers are recorded net in operating revenues on KCP&L's statement of income.

KCP&L collects sales taxes from customers and remits to state and local governments. These taxes are presented on a net basis on KCP&L's statement of income.

KCP&L records sale and purchase activity on a net basis in wholesale revenue or purchased power when transacting with Regional Transmission Organization (RTO)/Independent System Operator (ISO) markets.

Allowance for Doubtful Accounts

This reserve represents estimated uncollectible accounts receivable and is based on management's judgment considering historical loss experience and the characteristics of existing accounts. Provisions for losses on receivables are expensed

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to maintain the allowance at a level considered adequate to cover expected losses. Receivables are charged off against the reserve when they are deemed uncollectible.

Property Gains and Losses

Net gains and losses from the sales of assets, businesses and asset impairments are recorded in operating expenses.

Asset Impairments

Long-lived assets and finite lived intangible assets subject to amortization are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If the sum of the undiscounted expected future cash flows from an asset to be held and used is less than the carrying value of the asset, an asset impairment must be recognized in the financial statements. The amount of impairment recognized is the excess of the carrying value of the asset over its fair value.

Income Taxes

KCP&L has recognized deferred taxes for temporary book to tax differences using the liability method. The liability method requires that deferred tax balances be adjusted to reflect enacted tax rates that are anticipated to be in effect when the temporary differences reverse. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion of the deferred tax assets will not be realized.

KCP&L recognizes tax benefits based on a "more-likely-than-not" recognition threshold. In addition, KCP&L recognizes interest accrued related to unrecognized tax benefits in interest expense and penalties in non-operating expenses.

Great Plains Energy and its subsidiaries, including KCP&L, file consolidated federal and combined and separate state income tax returns. Income taxes for consolidated or combined subsidiaries are allocated to the subsidiaries based on separate company computations of income or loss. KCP&L's income tax provision includes taxes allocated based on its separate company income or loss.

KCP&L has established regulatory assets and liabilities for the additional future revenues to be collected from customers for deferred income taxes. Tax credits are recognized in the year generated except for certain KCP&L investment tax credits that have been deferred and amortized over the remaining service lives of the related properties.

Environmental Matters

Environmental costs are accrued when it is probable a liability has been incurred and the amount of the liability can be reasonably estimated.

Dividends Declared

In February 2011, KCP&L's Board of Directors declared a cash dividend payable to Great Plains Energy of \$25 million payable on March 17, 2011.

2. SUPPLEMENTAL CASH FLOW INFORMATION

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Other Operating Activities

	2010	2009
	(millions)	
Nuclear decommissioning expense	\$ 3.7	\$ 3.7
Deferred refueling outage costs	9.9	(7.1)
Pension and post-retirement benefit obligations	8.5	37.7
Iatan Nos. 1 and 2 impact of disallowed construction costs	13.0	-
Interest rate hedge settlement	-	(79.1)
Other deferred credits	4.7	25.3
Other	22.4	11.1
Total other operating activities	\$ 62.2	\$ (8.4)
Cash paid during the period:		
Interest	\$ 101.1	\$ 77.2
Income taxes	\$ 15.5	\$ 29.9
Non-cash investing activities:		
Liabilities assumed for capital expenditures	\$ 37.4	\$ 75.5

3. RECEIVABLES

KCP&L's other receivables at December 31, 2010 and 2009, consisted primarily of receivables from partners in jointly owned electric utility plants and wholesale sales receivables.

KCP&L sells all of its retail electric accounts receivable to its wholly owned subsidiary, Kansas City Power & Light Receivables Company (Receivables Company), which in turn sells an undivided percentage ownership interest in the accounts receivable to Victory Receivables Corporation, an independent outside investor. KCP&L sells its receivables at a fixed price based upon the expected cost of funds and charge-offs. These costs comprise KCP&L's loss on the sale of accounts receivable. KCP&L services the receivables and receives an annual servicing fee of 1.5% to 2.5% of the outstanding principal amount of the receivables sold to Receivables Company. KCP&L does not recognize a servicing asset or liability because management determined the collection agent fee earned by KCP&L approximates market value. In February 2011, the agreement was amended to extend the expiration date of the agreement from May 2011 to October 2011.

Information regarding KCP&L's sale of accounts receivable to Receivables Company is reflected in the following tables.

2010	KCP&L	Receivables Company
	(millions)	
Receivables (sold) purchased	\$ (1,341.0)	\$ 1,341.0
Gain (loss) on sale of accounts receivable ^(a)	(17.0)	16.8
Servicing fees	3.2	(3.2)
Fees to outside investor	-	(1.2)
Cash flows during the period		
Cash from customers transferred to Receivables Company	(1,337.4)	1,337.4
Cash paid to KCP&L for receivables purchased	1,320.7	(1,320.7)
Servicing fees	3.2	(3.2)
Interest on intercompany note	0.5	(0.5)

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2009	Receivables	
	KCP&L	Company
	(millions)	
Receivables (sold) purchased	\$ (1,172.4)	\$ 1,172.4
Gain (loss) on sale of accounts receivable ^(a)	(14.8)	14.6
Servicing fees	2.0	(2.0)
Fees to outside investor	-	(1.2)
Cash flows during the period		
Cash from customers transferred to Receivables Company	(1,167.6)	1,167.6
Cash paid to KCP&L for receivables purchased	1,153.0	(1,153.0)
Servicing fees	2.0	(2.0)
Interest on intercompany note	0.4	(0.4)

^(a) Any net gain (loss) is the result of the timing difference inherent in collecting receivables and over the life of the agreement will net to zero.

4. NUCLEAR PLANT

KCP&L owns 47% of Wolf Creek, its only nuclear generating unit. Wolf Creek is regulated by the Nuclear Regulatory Commission (NRC), with respect to licensing, operations and safety-related requirements.

Spent Nuclear Fuel and High-Level Radioactive Waste

Under the Nuclear Waste Policy Act of 1982, the Department of Energy (DOE) is responsible for the permanent disposal of spent nuclear fuel. KCP&L pays the DOE a quarterly fee of one-tenth of a cent for each kWh of net nuclear generation delivered and sold for the future disposal of spent nuclear fuel. These disposal costs are charged to fuel expense. In March 2010, the DOE filed a motion to withdraw its application to the NRC to construct a national repository for the disposal of spent nuclear fuel and high-level radioactive waste at Yucca Mountain, Nevada, which would bring the licensing process to an end. An NRC board denied the DOE's motion to withdraw its application in June 2010, and the DOE appealed that decision to the full NRC in early July 2010. The NRC has not yet decided that appeal. The question of the DOE's legal authority to withdraw its license application also is pending in multiple lawsuits filed with a federal appellate court. Oral argument to the court is set for late March 2011. Wolf Creek has an on-site storage facility designed to hold all spent fuel generated at the plant through 2025, and believes it will be able to expand on-site storage as needed past 2025. Management cannot predict when, or if, an alternative disposal site will be available to receive Wolf Creek's spent nuclear fuel and will continue to monitor this activity. See Note 14 for a related legal proceeding.

Low-Level Radioactive Waste

Wolf Creek disposes of most of its low-level radioactive waste (Class A waste) at an existing third-party repository in Utah. Management expects that the site located in Utah will remain available to Wolf Creek for disposal of its Class A waste. Wolf Creek has contracted with a waste processor that will process, take title and store in another state most of the remainder of Wolf Creek's low level radioactive waste (Classes B and C waste, which is higher in radioactivity but much lower in volume). Should on-site waste storage be needed in the future, Wolf Creek has current storage capacity on site for about four years' generation of Classes B and C waste and believes it will be able to expand that storage capacity as needed if it becomes necessary to do so.

Nuclear Plant Decommissioning Costs

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	Total Station	KCP&L's 47% Share
	(millions)	
Current cost of decommissioning (in 2008 dollars)	\$ 594	\$ 279
Future cost of decommissioning (in 2045-2053 dollars) ^(a)	2,575	1,210
Annual escalation factor	3.73%	
Annual return on trust assets ^(b)	6.83%	

^(a) Total future cost over an eight year decommissioning period.

^(b) The 6.83% rate of return is through 2025. The rate then systematically decreases through 2053 to 1.87% based on the assumption that the fund's investment mix will become increasingly more conservative as the decommissioning period approaches.

The MPSC and KCC require KCP&L and the other owners of Wolf Creek to submit an updated decommissioning cost study every three years and to propose funding levels. The most recent study was submitted to the MPSC and KCC in August 2008 and is the basis for the current cost of decommissioning estimates in the table below. KCC issued its order in August 2009 approving the 2008 decommissioning cost study, and approved funding levels in its order issued in November 2010. The MPSC does not explicitly approve or disapprove of the decommissioning cost study and issued its order approving the funding levels in May 2009.

Nuclear Decommissioning Trust Fund

In 2010 and 2009, KCP&L contributed approximately \$3.7 million to a tax-qualified trust fund to be used to decommission Wolf Creek. Amounts funded are charged to other operating expense and recovered in customers' rates. The funding level assumes a projected level of return on trust assets. If the actual return on trust assets is below the projected level or actual decommissioning costs are higher than estimated, KCP&L could be responsible for the balance of funds required; however, while there can be no assurances, management believes a rate increase would be allowed to recover decommissioning costs over the remaining life of the unit.

The following table summarizes the change in KCP&L's decommissioning trust fund.

December 31	2010	2009
Decommissioning Trust	(millions)	
Beginning balance January 1	\$ 112.5	\$ 96.9
Contributions	3.7	3.7
Earned income, net of fees	2.0	2.8
Net realized gains/(losses)	6.7	(5.5)
Net unrealized gains	4.3	14.6
Ending balance	\$ 129.2	\$ 112.5

The decommissioning trust is reported at fair value on the balance sheet and is invested in assets as detailed in the following table. At December 31, 2009, KCP&L was holding short-term investments in the decommissioning trust fund, which were invested in equity securities in early 2010 as a result of a change in the asset allocation of the trust to a higher proportion of equity securities given the 20-year extension of Wolf Creek's operating license approved by the NRC in November 2008.

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	December 31							
	2010				2009			
	Cost Basis	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value	Cost Basis	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(millions)							
Equity securities	\$ 73.4	\$ 13.1	\$ (1.0)	\$ 85.5	\$ 36.3	\$ 8.9	\$ (0.7)	\$ 44.5
Debt securities	38.1	2.6	(0.1)	40.6	35.3	2.1	-	37.4
Other	3.1	-	-	3.1	30.6	-	-	30.6
Total	\$ 114.6	\$ 15.7	\$ (1.1)	\$ 129.2	\$ 102.2	\$ 11.0	\$ (0.7)	\$ 112.5

The weighted average maturity of debt securities held by the trust at December 31, 2010, was approximately 7.6 years. The costs of securities sold are determined on the basis of specific identification. The following table summarizes the realized gains and losses from the sale of securities by the nuclear decommissioning trust fund.

	2010	2009
	(millions)	
Realized Gains	\$ 7.3	\$ 2.8
Realized Losses	(0.6)	(8.3)

Nuclear Insurance

The owners of Wolf Creek (Owners) maintain nuclear insurance for Wolf Creek for nuclear liability, nuclear property and accidental outage. These policies contain certain industry standard exclusions, including, but not limited to, ordinary wear and tear, and war. The nuclear property insurance programs subscribed to by members of the nuclear power generating industry include industry aggregate limits for acts of terrorism and related losses, including replacement power costs. There is no industry aggregate limit for liability claims, regardless of the number of acts affecting Wolf Creek or any other nuclear energy liability policy or the number of policies in place. An industry aggregate limit of \$3.2 billion plus any reinsurance recoverable by Nuclear Electric Insurance Limited (NEIL), the Owners' insurance provider, exists for property claims, including accidental outage power costs for acts of terrorism affecting Wolf Creek or any other nuclear energy facility property policy within twelve months from the date of the first act. These limits plus any recoverable reinsurance are the maximum amount to be paid to members who sustain losses or damages from these types of terrorist acts. In addition, industry-wide retrospective assessment programs (discussed below) can apply once these insurance programs have been exhausted.

In the event of a catastrophic loss at Wolf Creek, the insurance coverage may not be adequate to cover property damage and extra expenses incurred. Uninsured losses, to the extent not recovered through rates, would be assumed by KCP&L and the other owners and could have a material adverse effect on KCP&L's results of operations, financial position and cash flows.

Nuclear Liability Insurance

Pursuant to the Price-Anderson Act, which was reauthorized through December 31, 2025, by the Energy Policy Act of 2005, the Owners are required to insure against public liability claims resulting from nuclear incidents to the full limit of public liability, which is currently \$12.6 billion. This limit of liability consists of the maximum available commercial insurance of \$0.4 billion and the remaining \$12.2 billion is provided through an industry-wide retrospective assessment program mandated by law, known as the Secondary Financial Protection (SFP) program. Under the SFP program, the Owners can be assessed up to \$117.5 million (\$55.2 million, KCP&L's 47% share) per incident at any commercial reactor in the country, payable at no more than \$17.5 million (\$8.2 million, KCP&L's 47% share) per incident per year.

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This assessment is subject to an inflation adjustment based on the Consumer Price Index and applicable premium taxes. In addition, the U.S. Congress could impose additional revenue-raising measures to pay claims.

Nuclear Property Insurance

The Owners carry decontamination liability, premature decommissioning liability and property damage insurance from NEIL for Wolf Creek totaling approximately \$2.8 billion (\$1.3 billion, KCP&L's 47% share). In the event of an accident, insurance proceeds must first be used for reactor stabilization and site decontamination in accordance with a plan mandated by the NRC. KCP&L's share of any remaining proceeds can be used for further decontamination, property damage restoration and premature decommissioning costs. Premature decommissioning coverage applies only if an accident at Wolf Creek exceeds \$500 million in property damage and decontamination expenses, and only after trust funds have been exhausted.

Accidental Nuclear Outage Insurance

The Owners also carry additional insurance from NEIL to cover costs of replacement power and other extra expenses incurred in the event of a prolonged outage resulting from accidental property damage at Wolf Creek.

Under all NEIL policies, the Owners are subject to retrospective assessments if NEIL losses, for each policy year, exceed the accumulated funds available to the insurer under that policy. The estimated maximum amount of retrospective assessments under the current policies could total approximately \$26.2 million (\$12.3 million, KCP&L's 47% share) per policy year.

5. REGULATORY MATTERS

KCP&L's Comprehensive Energy Plan

KCP&L's Comprehensive Energy Plan included construction of Iatan No. 2, wind generation, environmental upgrades at certain coal-fired generating stations, infrastructure investments, and energy efficiency, affordability and demand response programs. With the construction of Iatan No. 2 completed in 2010, the remaining component of KCP&L's Comprehensive Energy Plan is to obtain state regulatory approval to include the cost of Iatan No. 2 in rate base and begin recovering the investment in rates.

In August 2010, Iatan No. 2 successfully completed in-service testing, which was confirmed by KCC in October 2010, but is still subject to confirmation by the MPSC, which is expected during the current Missouri rate case.

In the fourth quarter of 2010, Great Plains Energy and KCP&L completed a final cost estimate for Iatan No. 2. The final cost estimate and previous cost estimate ranges are shown in the following table. The cost estimate ranges do not include AFUDC or the cost of common facilities that were identified at the time of the start-up of the Iatan No. 1 environmental project that will be used by both Iatan No. 1 and Iatan No. 2.

	Final Cost Estimate Range	Previous Estimate Range	Change
		(millions)	
KCP&L's 55% share of Iatan No. 2	\$ 905 - \$ 917	\$ 919 - \$ 941	\$ (14) - \$ (24)

Kansas Regulatory Proceedings

In December 2009, KCP&L filed a request with KCC to increase retail electric annual revenues by \$55.2 million. The request was subsequently adjusted by KCP&L during the rate case proceedings to \$50.9 million as the net result of updates to the case. The request included costs related to Iatan No. 2, a new coal-fired generation unit, upgrades to the

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transmission and distribution system to improve reliability and overall increased costs of service.

In November 2010, KCC issued its order, effective December 1, 2010, authorizing an increase in annual revenues of \$21.8 million, a return on equity of 10.0%, an equity ratio of approximately 49.7% and a Kansas jurisdictional rate base of \$1.781 billion. The annual revenue increase was subsequently adjusted by KCC in a January 2011 reconsideration order to \$22.0 million. In February 2011, KCC issued an order granting KCP&L and another party to the case their respective petitions for reconsideration regarding rate case expenses. The \$22.0 million annual revenue increase is considered as interim subject to refund or true-up pending the outcome of the reconsideration proceedings regarding rate case expenses. Also in February 2011, KCP&L and another party to the case filed petitions for judicial review with the Court of Appeals of the State of Kansas, which are stayed until conclusion of the reconsideration proceedings. The rates authorized by KCC will be effective unless and until modified by KCC or stayed by a court.

Accounting rules state that when it becomes probable that part of the cost of a recently completed plant will be disallowed for rate-making purposes and a reasonable estimate of the amount of the disallowance can be made, the estimated amount of the probable disallowance shall be deducted from the reported cost of the plant and recognized as a loss. As a result of disallowances in the KCC order, KCP&L recognized Kansas jurisdictional losses of \$4.4 million for construction costs related to Iatan No. 2 and \$2.0 million for construction costs related to the Iatan No. 1 environmental project. Management determined it is probable that the MPSC would disallow these costs as well in KCP&L's pending rate case. Therefore, KCP&L's Missouri jurisdictional portion of these costs was recognized as a loss in addition to the KCP&L Kansas jurisdictional portion resulting in a \$13.0 million pre-tax loss for KCP&L's construction costs incurred through December 31, 2010.

Missouri Regulatory Proceedings

The following table summarizes pending requests for retail rate increases with the MPSC.

Rate Jurisdiction	File Date	Annual Revenue Increase (millions)	Return on Equity	Rate-Making Equity Ratio
KCP&L - Missouri ^(a)	6/4/2010	\$ 92.1 ^(b)	11.00% ^(b)	46.16% ^(b)

^(a) The request includes costs related to Iatan No. 2, a new coal-fired generation unit, upgrades to the transmission and distribution system to improve reliability and overall increased costs of service. It also includes increased coal transportation costs due to the expiration in 2010 of the majority of KCP&L's current coal transportation contracts. Any authorized changes to retail rates are expected to be effective in May 2011.

^(b) The requested increase was adjusted by KCP&L in a February 22, 2011, filing with the MPSC to \$55.8 million mainly due to lower fuel and purchased power costs, as there is no fuel recovery mechanism, and increased deferred income taxes from bonus depreciation. The lower fuel and purchased power costs were driven by more favorable coal transportation costs and lower actual 2010 fuel and purchased power costs than the amounts included in the June 4, 2010, initial request. The requested return on equity was adjusted by KCP&L to 10.75% and the rate-making equity ratio was adjusted to 46.286%.

KCP&L (Missouri jurisdiction only) was granted construction accounting as part of the Comprehensive Energy Plan, which includes deferring KCP&L's share of Iatan No. 2 operating costs, depreciation expense and carrying costs (interest) offset by Iatan No. 2's system energy value to a regulatory asset rather than impacting the income statement until new rates are effective.

In November 2010, the MPSC staff filed its construction audit and prudence review regarding construction expenditures

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through June 30, 2010, for Iatan No. 2 and the Iatan No. 1 environmental project. The MPSC staff recommended disallowances of approximately \$130 million and \$70 million of the total costs incurred through June 30, 2010, for Iatan No. 2 and the Iatan No. 1 environmental project, respectively, representing all audited expenditures above the associated December 2006 control budget estimates of approximately \$1.685 billion and \$377 million.

The MPSC staff also filed testimony in KCP&L's rate case in November 2010. The MPSC staff's testimony recommended a return on equity range of 8.5% to 9.5% and a revenue increase/(decrease) range of approximately \$(0.2) million to \$14 million for KCP&L. On February 22, 2011, the MPSC Staff filed updated testimony recommending the same return on equity range of 8.5% to 9.5% and a revenue increase range of approximately \$2.2 million to \$17.0 million for KCP&L. The revenue recommendations reflect the MPSC staff's proposed construction cost disallowances of all audited expenditures as of October 31, 2010, above the control budget estimates, among other differences from KCP&L's request.

Hearings began in late January 2011 and ran through early February 2011 for KCP&L. The MPSC Staff filed reconciliations of the differences between its February 22, 2011, recommendations and KCP&L's February 22, 2011, recommendations and hearings were held March 3 – 4, 2011. New rates are expected to go into effect in May 2011.

SPP and NERC Audits

In November 2009, the Southwest Power Pool, Inc. (SPP) and the North American Electric Reliability Corporation (NERC) conducted a scheduled audit of KCP&L regarding compliance with NERC reliability and critical infrastructure protection standards. KCP&L received the final audit report alleging violation of certain standards and management anticipates paying a penalty that will have an immaterial impact to cash flows and results of operations.

Energy Efficiency

KCP&L has implemented various energy efficiency programs. KCP&L also agreed in the Collaboration Agreement to pursue initiatives, including energy efficiency, designed to offset CO₂ emissions. KCP&L currently recovers energy efficiency program expenses on a deferred basis with no recovery mechanism for associated lost revenues. An MPSC rulemaking proceeding in Missouri to address recovery of and earnings on investments in energy efficiency programs is near completion with final rules expected to be effective in the second quarter of 2011. KCP&L will evaluate alternatives for future energy efficiency programs under these new rules.

Regulatory Assets and Liabilities

KCP&L has recorded assets and liabilities on its balance sheet resulting from the effects of the ratemaking process, which would not otherwise be recorded if KCP&L was not regulated. Regulatory assets represent incurred costs that are probable of recovery from future revenues. Regulatory liabilities represent future reductions in revenues or refunds to customers.

Management regularly assesses whether regulatory assets and liabilities are probable of future recovery or refund by considering factors such as decisions by the MPSC, KCC or FERC in KCP&L's rate case filings; decisions in other regulatory proceedings, including decisions related to other companies that establish precedent on matters applicable to KCP&L; and changes in laws and regulations. If recovery or refund of regulatory assets or liabilities is not approved by regulators or is no longer deemed probable, these regulatory assets or liabilities are recognized in the current period results of operations. KCP&L's continued ability to meet the criteria for recording regulatory assets and liabilities may be affected in the future by restructuring and deregulation in the electric industry or changes in accounting rules. In the event that the criteria no longer applied to any or all of KCP&L's operations, the related regulatory assets and liabilities would be written off unless an appropriate regulatory recovery mechanism is provided. Additionally, these factors could result in an impairment on utility plant assets.

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KCP&L's regulatory assets and liabilities are detailed in the following table.

	December 31	
	2010	2009
Regulatory Assets	(millions)	
Taxes recoverable through future rates	\$ 222.3	\$ 201.4
Asset retirement obligations	27.5	23.8
Pension settlements	9.0 (a)	13.5
Pension and post-retirement costs	377.1 (b)	395.0
Deferred customer programs	44.7 (c)	35.6
Rate case expenses	12.3 (d)	7.4
Skill set realignment costs	4.8 (e)	6.1
Fuel adjustment clauses	8.4 (d)	0.7
Acquisition transition costs	29.3 (f)	29.3
Iatan No. 1 and Common facilities depreciation and carrying costs	15.1 (g)	4.6
Iatan No. 2 construction accounting costs	17.2 (h)	-
Other	3.4 (i)	5.2
Total	\$ 771.1	\$ 722.6
Regulatory Liabilities		
Taxes refundable through future rates	\$ 105.1	\$ 123.8
Emission allowances	85.9	86.2
Asset retirement obligations	44.9	33.4
Other	10.5	7.3
Total	\$ 246.4	\$ 250.7

- (a) \$5.0 million not included in rate base and amortized through 2012.
- (b) Represents the funded status of the pension plans more than offset by related liabilities. Also represents financial and regulatory accounting method differences not included in rate base that will be eliminated over the life of the pension plans.
- (c) \$13.2 million not included in rate base and amortized over various periods.
- (d) Not included in rate base and amortized over various periods.
- (e) \$2.8 million not included in rate base and amortized through 2017.
- (f) Not included in rate base. The MPSC order provided for the deferral of transition costs to be amortized over a five-year period to the extent that synergy savings exceed transition cost amortization. KCP&L settled its first post-transaction rate cases and the settlement agreements did not address transition costs. KCP&L will continue to defer transition costs until amortization is ordered by the MPSC. KCC order approved the deferral of up to \$10.0 million of transition costs to be amortized over a five-year period beginning with rates effective in December 2010.
- (g) \$11.6 million not included in rate base and under consideration in the pending Missouri rate case.
- (h) Not included in rate base and under consideration in the pending Missouri rate case.
- (i) Certain insignificant items are not included in rate base and amortized over various periods.

6. INTANGIBLE ASSETS

KCP&L's intangible assets on the balance sheet are detailed in the following table.

	December 31, 2010		December 31, 2009	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
	(millions)			
Computer software	\$ 168.2	\$ (118.0)	\$ 147.0	\$ (106.3)
Transmission line	5.8	-	-	-

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KCP&L's amortization expense related to intangible assets was \$12.2 million and \$10.4 million, respectively for 2010 and 2009. KCP&L's estimated amortization expense related to intangible assets for 2011 through 2015 for the intangible assets included in the balance sheet at December 31, 2010, is \$11.9 million, \$10.0 million, \$7.6 million, \$4.3 million and \$2.3 million, respectively.

7. ASSET RETIREMENT OBLIGATIONS

Asset retirement obligations associated with tangible long-lived assets are those for which a legal obligation exists under enacted laws, statutes and written or oral contracts, including obligations arising under the doctrine of promissory estoppel. These liabilities are recognized at estimated fair value as incurred and capitalized as part of the cost of the related long-lived assets and depreciated over their useful lives. Accretion of the liabilities due to the passage of time is recorded to a regulatory asset and/or liability. Changes in the estimated fair values of the liabilities are recognized when known.

KCP&L has AROs related to decommissioning Wolf Creek, site remediation of its Spearville Wind Energy Facilities, asbestos abatement and for removal of storage tanks, an ash pond and landfill.

Management has identified an additional asbestos ARO. Certain wiring used in generating stations includes asbestos insulation, which would require special handling if disturbed. Due to the inability to reasonably estimate the quantities or the amount of disturbance that will be necessary during dismantlement at the end of the life of a plant, a fair value of the obligation cannot be reasonably estimated at this time. Management will continue to monitor the obligation and will recognize a liability in the period in which sufficient information becomes available to reasonably estimate its fair value.

The following table summarizes the change in KCP&L's AROs.

	2010	2009
	(millions)	
Beginning balance	\$ 119.8	\$ 111.9
Additions	2.0	0.6
Accretion	7.9	7.3
Ending balance	\$ 129.7	\$ 119.8

8. PENSION PLANS AND OTHER EMPLOYEE BENEFITS

KCP&L does not have a defined pension plan; however, KCP&L employees and officers participate in Great Plains Energy's pension plans. Great Plains Energy maintains defined benefit pension plans for substantially all active and inactive employees, including officers, of KCP&L, GMO, and Wolf Creek Nuclear Operating Corporation (WCNOC) and incurs significant costs in providing the plans. Pension benefits under these plans reflect the employees' compensation, years of service and age at retirement.

KCP&L records pension expense in accordance with rate orders from the MPSC and KCC that allow the difference between pension costs under GAAP and pension costs for ratemaking to be recognized as a regulatory asset or liability. This difference between financial and regulatory accounting methods is due to timing and will be eliminated over the life of the pension plans.

In addition to providing pension benefits, Great Plains Energy provides certain post-retirement health care and life insurance benefits for substantially all retired employees of KCP&L, GMO, and WCNOC. The cost of post-retirement

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benefits charged to KCP&L is accrued during an employee's years of service and recovered through rates.

The following pension benefits tables provide information relating to the funded status of all defined benefit pension plans on an aggregate basis as well as the components of Great Plains Energy's net periodic benefit costs. For financial reporting purposes, the market value of plan assets is the fair value. KCP&L uses a five-year smoothing of assets to determine fair value for regulatory reporting purposes. As a result of the GMO acquisition on July 14, 2008, Great Plains Energy's 2008 pension and post-retirement expenses under GAAP increased \$2.4 million and \$1.1 million, respectively. The underfunded status of the pension and other post-retirement benefit plans transferred at the date of acquisition was \$48.9 million. Net periodic benefit costs reflect total plan benefit costs prior to the effects of capitalization and sharing with joint-owners of power plants.

	Pension Benefits		Other Benefits	
	2010	2009	2010	2009
Change in projected benefit obligation (PBO)	(millions)			
PBO at beginning of year	\$ 836.3	\$ 772.5	\$ 148.9	\$ 135.4
Service cost	30.3	29.1	3.8	4.1
Interest cost	49.3	47.3	8.8	8.3
Contribution by participants	-	-	5.6	5.3
Amendments	0.5	5.7	-	3.4
Actuarial (gain) loss	55.1	33.1	(12.5)	3.9
Benefits paid	(60.1)	(49.3)	(11.0)	(11.5)
Settlements	-	(2.1)	-	-
PBO at end of plan year	\$ 911.4	\$ 836.3	\$ 143.6	\$ 148.9
Change in plan assets				
Fair value of plan assets at beginning of year	\$ 488.2	\$ 418.7	\$ 52.0	\$ 38.9
Actual return on plan assets	62.7	75.1	0.5	0.7
Contributions by employer and participants	64.5	42.1	23.9	22.0
Benefits paid	(57.8)	(47.7)	(10.6)	(9.6)
Fair value of plan assets at end of plan year	\$ 557.6	\$ 488.2	\$ 65.8	\$ 52.0
Funded status at end of year	\$ (353.8)	\$ (348.1)	\$ (77.8)	\$ (96.9)
Amounts recognized in the consolidated balance sheets				
Current pension and other post-retirement liability	\$ (3.1)	\$ (3.7)	\$ (1.0)	\$ (0.9)
Noncurrent pension liability and other post-retirement liability	(350.7)	(344.4)	(76.8)	(96.0)
Net amount recognized before regulatory treatment	(353.8)	(348.1)	(77.8)	(96.9)
Accumulated OCI or regulatory asset/liability	403.2	386.2	54.8	74.0
Net amount recognized at December 31	\$ 49.4	\$ 38.1	\$ (23.0)	\$ (22.9)
Amounts in accumulated OCI or regulatory asset/liability not yet recognized as a component of net periodic cost:				
Actuarial loss	\$ 219.5	\$ 227.8	\$ 8.5	\$ 19.3
Prior service cost	15.3	19.4	44.1	51.3
Transition obligation	-	0.1	3.0	4.3
Other	168.4	138.9	(0.8)	(0.9)
Net amount recognized at December 31	\$ 403.2	\$ 386.2	\$ 54.8	\$ 74.0

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	Pension Benefits		Other Benefits	
	2010	2009	2010	2009
(millions)				
Components of net periodic benefit costs				
Service cost	\$ 30.3	\$ 29.1	\$ 3.8	\$ 4.1
Interest cost	49.3	47.3	8.8	8.3
Expected return on plan assets	(36.6)	(32.4)	(2.1)	(1.6)
Prior service cost	4.6	4.2	7.2	6.9
Recognized net actuarial (gain) loss	37.4	36.3	(0.1)	(0.4)
Transition obligation	0.1	0.1	1.3	1.3
Settlement charges	-	0.1	-	-
Net periodic benefit costs before regulatory adjustment	85.1	84.7	18.9	18.6
Regulatory adjustment	(32.3)	(28.4)	-	(0.3)
Net periodic benefit costs	52.8	56.3	18.9	18.3
Other changes in plan assets and benefit obligations recognized in OCI or regulatory assets/liabilities				
Current year net (gain) loss	29.1	(9.2)	(10.9)	(0.2)
Amortization of gain (loss)	(37.4)	(36.3)	0.1	0.4
Prior service cost	0.5	5.7	-	24.8
Amortization of prior service cost	(4.6)	(4.2)	(7.2)	(6.9)
Transition obligation	-	-	-	1.2
Amortization of transition obligation	(0.1)	(0.1)	(1.3)	(1.3)
Other regulatory activity	29.5	10.1	0.1	(3.1)
Total recognized in OCI or regulatory asset/liability	17.0	(34.0)	(19.2)	14.9
Total recognized in net periodic benefit costs and OCI or regulatory asset/liability	\$ 69.8	\$ 22.3	\$ (0.3)	\$ 33.2

For financial reporting purposes, the estimated prior service cost, net loss and transition costs for the defined benefit plans that will be amortized from accumulated OCI or a regulatory asset into net periodic benefit cost in 2011 for Great Plains Energy are \$4.5 million, \$38.5 million and \$0.1 million, respectively. For financial reporting purposes, net actuarial gains and losses are recognized on a rolling five-year average basis. For regulatory reporting purposes, net actuarial gains and losses are amortized over ten years. The estimated prior service cost, net gain and transition costs for the other post-retirement benefit plans that will be amortized from accumulated OCI or a regulatory asset into net periodic benefit cost for Great Plains Energy in 2011 are \$7.2 million, \$(1.0) million and \$1.3 million, respectively.

The accumulated benefit obligation (ABO) for all of Great Plains Energy's defined benefit pension plans was \$808.8 million and \$741.4 million at December 31, 2010 and 2009, respectively. The PBO, ABO and the fair value of plan assets at plan year-end are aggregated by funded and under funded plans in the following table.

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	2010	2009
(millions)		
Pension plans with the ABO in excess of plan assets		
Projected benefit obligation	\$ 911.4	\$ 836.3
Accumulated benefit obligation	808.8	741.4
Fair value of plan assets	557.6	488.2
Pension plans with plan assets in excess of the ABO		
Projected benefit obligation	\$ -	\$ -
Accumulated benefit obligation	-	-
Fair value of plan assets	-	-

The expected long-term rate of return on plan assets represents Great Plains Energy's estimate of the long-term return on plan assets and is based on historical and projected rates of return for current and planned asset classes in the plans' investment portfolios. Assumed projected rates of return for each asset class were selected after analyzing historical experience and future expectations of the returns of various asset classes. Based on the target asset allocation for each asset class, the overall expected rate of return for the portfolios was developed and adjusted for the effect of projected benefits paid from plan assets and future plan contributions. The following tables provide the weighted-average assumptions used to determine benefit obligations and net costs.

Weighted average assumptions used to determine the benefit obligation at plan year-end	Pension Benefits		Other Benefits	
	2010	2009	2010	2009
Discount rate	5.54%	5.92%	5.50%	5.87%
Rate of compensation increase	4.08%	4.26%	4.06%	4.25%

Weighted average assumptions used to determine net costs for years ended at December 31	Pension Benefits		Other Benefits	
	2010	2009	2010	2009
Discount rate	5.92%	6.11%	5.87%	6.10%
Expected long-term return on plan assets	8.00%	8.00%	4.25% *	4.00% *
Rate of compensation increase	4.26%	4.27%	4.25%	4.25%

* after tax

For pension benefits, Great Plains Energy's 2011 projected weighted average long-term rate of return on plan assets is 7.3%, a 0.7% decrease from 2010. The reduction in the rate of return is expected to increase 2011 GAAP pension expense approximately \$4 million.

Great Plains Energy expects to contribute \$104.6 million to the pension plans in 2011 to meet Employee Retirement Income Security Act of 1974 (ERISA) funding requirements and regulatory orders, the majority of which is expected to be paid by KCP&L. Great Plains Energy's funding policy is to contribute amounts sufficient to meet the ERISA funding requirements and MPSC and KCC rate orders plus additional amounts as considered appropriate; therefore, actual contributions may differ from expected contributions. Great Plains Energy also expects to contribute \$15.8 million to other post-retirement benefit plans in 2011, the majority of which is expected to be paid by KCP&L.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid through 2020.

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	Pension Benefits	Other Benefits
	(millions)	
2011	\$ 71.4	\$ 8.4
2012	66.9	8.3
2013	66.2	8.4
2014	65.3	8.6
2015	67.9	8.6
2016-2020	370.0	47.7

Pension plan assets are managed in accordance with “prudent investor” guidelines contained in the ERISA requirements. The investment strategy supports the objective of the fund, which is to earn the highest possible return on plan assets within a reasonable and prudent level of risk. The portfolios are invested, and periodically rebalanced, to achieve targeted allocations of approximately 28% U.S. large cap and small cap equity securities, 22% international equity securities, 37% fixed income securities, 7% real estate and 6% commodities. Fixed income securities include domestic and foreign corporate bonds, collateralized mortgage obligations and asset-backed securities, U.S. government agency, state and local obligations, U.S. treasury notes and money market funds.

The fair values of Great Plains Energy’s pension plan assets at December 31, 2010 and 2009, by asset category are in the following tables.

Description	December 31 2010	Fair Value Measurements Using		
		Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
		(millions)		
Pension Plans				
Equity securities				
U.S. ^(a)	\$ 158.5	\$ 90.5	\$ 68.0	\$ -
International ^(b)	122.4	39.4	83.0	-
Limited partnerships	0.1	-	-	0.1
Real estate ^(c)	30.3	-	-	30.3
Commodities ^(d)	37.0	-	37.0	-
Fixed income securities				
Fixed income funds ^(e)	148.7	23.0	125.7	-
U.S. Treasury notes	1.8	1.8	-	-
U.S. Agency, state and local obligations	14.8	-	14.8	-
U.S. corporate bonds ^(f)	24.2	-	24.2	-
Foreign corporate bonds	1.5	-	1.5	-
Hedge funds ^(g)	8.4	-	-	8.4
Total	\$ 547.7	\$ 154.7	\$ 354.2	\$ 38.8
Cash equivalents - money market funds	9.9			
Total Pension Plans	\$ 557.6			

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Description	December 31 2009	Fair Value Measurements Using		
		Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
(millions)				
Pension Plans				
Equity securities				
U.S. ^(a)	\$ 188.8	\$ 102.9	\$ 85.9	\$ -
International ^(b)	75.2	18.4	56.8	-
Limited partnerships	0.1	-	-	0.1
Real estate ^(c)	26.8	-	-	26.8
Commodities ^(d)	17.6	-	17.6	-
Fixed income securities				
Fixed income funds ^(e)	117.9	3.0	114.9	-
U.S. Treasury notes	1.3	1.3	-	-
U.S. Agency, state and local obligations	18.7	-	18.7	-
U.S. corporate bonds ^(f)	25.5	0.9	24.6	-
Foreign corporate bonds	1.2	-	1.2	-
Hedge fund	2.4	-	-	2.4
Total	\$ 475.5	\$ 126.5	\$ 319.7	\$ 29.3
Cash equivalents - money market funds	12.7			
Total Pension Plans	\$ 488.2			

^(a) At December 31, 2010 and 2009, this category is comprised of \$90.5 million and \$102.9 million, respectively, of traded mutual funds valued at daily listed prices and \$68.0 million and \$85.9 million, respectively, of institutional common/collective trust funds valued at daily Net Asset Values (NAV) per share.

^(b) At December 31, 2010 and 2009, this category is comprised of \$39.4 million and \$18.4 million, respectively, of traded mutual funds valued at daily listed prices and \$83.0 million and \$56.8 million, respectively, of institutional common/collective trust funds valued at daily NAV per share.

^(c) This category is comprised of institutional common/collective trust funds and a limited partnership valued at NAV on a quarterly basis.

^(d) This category is comprised of institutional common/collective trust funds valued at daily NAV per share.

^(e) At December 31, 2010 and 2009, this category is comprised of \$23.0 million and \$3.0 million, respectively, of traded mutual funds valued at daily listed prices and \$125.7 million and \$114.9 million, respectively, of institutional common/collective trust funds valued at daily NAV per share.

^(f) At December 31, 2010 and 2009, this category is comprised of \$13.9 million and \$13.0 million, respectively, of corporate bonds, \$8.0 million and \$9.3 million, respectively, of collateralized mortgage obligations and \$2.3 million and \$3.2 million, respectively, of other asset-backed securities.

^(g) This category is comprised of closely-held limited partnerships valued at NAV on a quarterly basis.

The following tables reconcile the beginning and ending balances for all of Great Plains Energy's level 3 pension plan

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assets measured at fair value on a recurring basis for 2010 and 2009.

Fair Value Measurements Using Significant Unobservable Inputs (Level 3)				
Description	Real Estate	Hedge Fund	Limited Partnerships	Total
	(millions)			
Balance January 1, 2010	\$ 26.8	\$ 2.4	\$ 0.1	\$ 29.3
Actual return on plan assets				
Relating to assets still held	2.5	(0.2)	-	2.3
Relating to assets sold	-	(0.7)	-	(0.7)
Purchase, issuances, and settlements	1.0	6.9	-	7.9
Transfers in and/or out of Level 3	-	-	-	-
Balance December 31, 2010	\$ 30.3	\$ 8.4	\$ 0.1	\$ 38.8

Fair Value Measurements Using Significant Unobservable Inputs (Level 3)				
Description	Real Estate	Hedge Fund	Limited Partnerships	Total
	(millions)			
Balance January 1, 2009	\$ 36.9	\$ 6.6	\$ 0.5	\$ 44.0
Actual return on plan assets				
Relating to assets still held	(10.2)	0.1	0.2	(9.9)
Relating to assets sold	0.1	(1.3)	-	(1.2)
Purchase, issuances, and settlements	-	(3.0)	(0.6)	(3.6)
Transfers in and/or out of Level 3	-	-	-	-
Balance December 31, 2009	\$ 26.8	\$ 2.4	\$ 0.1	\$ 29.3

Other post-retirement plan assets are also managed in accordance with “prudent investor” guidelines contained in the ERISA requirements. The investment strategy supports the objective of the funds, which is to preserve capital, maintain sufficient liquidity and earn a consistent rate of return. Other post-retirement plan assets are invested entirely in fixed income securities which may include domestic and foreign corporate bonds, collateralized mortgage obligations and asset-backed securities, U.S. government agency, state and local obligations, U.S. Treasury notes and money market funds.

The fair values of Great Plains Energy’s other post-retirement plan assets at December 31, 2010 and 2009, by asset category are in the following tables.

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Description	December 31 2010	Fair Value Measurements Using		
		Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
(millions)				
Other Post-Retirement Benefit Plans				
Fixed income				
U.S. Treasury	\$ 12.1	\$ 12.1	\$ -	\$ -
U.S. Agency	21.7	-	21.7	-
State and local obligations	0.5	-	0.5	-
Corporate bonds ^(a)	11.4	-	11.4	-
Foreign corporate bonds	1.0	-	1.0	-
Mutual funds	0.1	0.1	-	-
Total	\$ 46.8	\$ 12.2	\$ 34.6	\$ -
Cash and cash equivalents - money market funds	19.0			
Total Other Post-Retirement Benefit Plans	\$ 65.8			

^(a) This category is comprised of \$9.2 million of corporate bonds, \$0.9 million of collateralized mortgage obligations and \$1.3 million of other asset-backed securities.

Description	December 31 2009	Fair Value Measurements Using		
		Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
(millions)				
Other Post-Retirement Benefit Plans				
Fixed income				
U.S. Treasury	\$ 0.8	\$ 0.8	\$ -	\$ -
U.S. Agency	0.6	-	0.6	-
Corporate bonds	1.0	-	1.0	-
Mutual funds	0.1	0.1	-	-
Total	\$ 2.5	\$ 0.9	\$ 1.6	\$ -
Cash and cash equivalents - money market funds	49.5			
Total Other Post-Retirement Benefit Plans	\$ 52.0			

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. The cost trend assumed for 2010 and 2011 was 8.0%, with the rate declining through 2018 to the ultimate cost trend rate of 5%. The health care plan requires retirees to make monthly contributions on behalf of themselves and their dependents in an

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amount determined by Great Plains Energy.

The effects of a one-percentage point change in the assumed health care cost trend rates, holding all other assumptions constant, at December 31, 2010, are detailed in the following table. The results reflect the increase in the Medicare Part D employer subsidy which is assumed to increase with the medical trend and employer caps on post-65 plans.

	Increase	Decrease
	(millions)	
Effect on total service and interest component	\$ 0.2	\$ (0.3)
Effect on post-retirement benefit obligation	2.2	(2.1)

Employee Savings Plans

Great Plains Energy has defined contribution savings plans (401(k)) that cover substantially all employees. Great Plains Energy matches employee contributions, subject to limits. KCP&L's annual cost of the plans was approximately \$6.5 million in 2010 and 2009.

9. EQUITY COMPENSATION

KCP&L does not have an equity compensation plan; however, certain employees participate in Great Plains Energy's Long-Term Incentive Plan. Great Plains Energy's Long-Term Incentive Plan is an equity compensation plan approved by Great Plains Energy's shareholders. The Long-Term Incentive Plan permits the grant of restricted stock, stock options, limited stock appreciation rights, director shares, director deferred share units and performance shares to directors, officers and other employees of Great Plains Energy and KCP&L. The maximum number of shares of Great Plains Energy common stock that can be issued under the plan is 5.0 million. Common stock shares delivered by Great Plains Energy under the Long-Term Incentive Plan may be authorized but unissued, held in the treasury or purchased on the open market (including private purchases) in accordance with applicable securities laws. Great Plains Energy has a policy of delivering newly issued shares, or shares surrendered by Long-Term Incentive Plan participants on account of withholding taxes and held in treasury, or both, and does not expect to repurchase common shares during 2011 to satisfy performance share payments, stock option exercises and director deferred share unit conversion. Forfeiture rates are based on historical forfeitures and future expectations and are reevaluated annually.

The following table summarizes KCP&L's equity compensation expense and associated income tax benefits.

	2010	2009
	(millions)	
Compensation expense	\$ 3.0	\$ 4.3
Income tax benefits	0.5	0.8

Performance Shares

The payment of performance shares is contingent upon achievement of specific performance goals over a stated period of time as approved by the Compensation and Development Committee of Great Plains Energy's Board of Directors. The number of performance shares ultimately paid can vary from the number of shares initially granted depending on Great Plains Energy's performance over stated performance periods and Great Plains Energy's stock price following the end of the performance period as compared to the stock price on the grant date. Compensation expense for performance shares issued subsequent to the amendment discussed below is calculated by taking the change in fair value between reporting periods for the portion for which the requisite service has been rendered. Dividends are accrued over the vesting period

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and paid in cash based on the number of performance shares ultimately paid.

The fair value of performance share awards is estimated using a Monte Carlo simulation technique that uses the closing stock price at the valuation date and incorporates assumptions for inputs of expected volatilities, dividend yield and risk-free rates. Expected volatility is based on daily stock price change during a historical period commensurate with the remaining term of the performance period of the grant. The risk-free rate is based upon the rate at the time of the evaluation for zero-coupon government bonds with a maturity consistent with the remaining performance period of the grant. The dividend yield is based on the most recent dividends paid and the actual closing stock price on the valuation date. For shares granted in 2010, inputs for expected volatility, dividend yield and risk-free rates were 31%, 4.65%, and 1.2%, respectively.

Performance share activity for 2010 is summarized in the following table. Performance adjustment represents the number of shares of common stock related to performance shares ultimately issued that can vary from the number of performance shares initially granted depending on Great Plains Energy's performance over stated performance periods and Great Plains Energy's stock price following the end of the performance period as compared to the stock price on the grant date.

	Performance Shares	Grant Date Fair Value*
Beginning balance	294,641	\$ 13.62
Performance adjustment	(21,674)	
Granted	231,598	23.37
Earned	(8,433)	10.87
Forfeited	(64,348)	20.54
Ending balance	431,784	18.01

* weighted-average

At December 31, 2010, the remaining weighted-average contractual term was 1.3 years. The weighted-average grant-date fair value of shares granted was \$23.37 and \$15.04 in 2010 and 2009, respectively. At December 31, 2010, there was \$1.8 million of total unrecognized compensation expense, net of forfeiture rates, related to performance shares granted under the Long-Term Incentive Plan, which will be recognized over the remaining weighted-average contractual term. The total fair value of performance shares earned and paid in 2010 was insignificant. There were no performance shares earned and paid during 2009.

Amendment to Performance Shares

In May 2009, the independent members of the Great Plains Energy Board of Directors (Board) approved amendments to certain outstanding performance share agreements (Original Agreements) for the 2007-2009 and 2008-2010 performance periods. The Original Agreements, as amended, are referred to as the Amended Agreements. Due to changes in economic and financial market conditions since the Original Agreements were entered into, the Compensation and Development Committee (Committee) and Board determined that the Original Agreements no longer provided meaningful incentives.

The Original Agreements granted performance shares based on a single performance metric – Great Plains Energy's total shareholder return (TSR) as compared to the Edison Electric Institute TSR index for electric utility companies over the relevant performance periods. The Amended Agreements provide for a combination of performance shares and time-based restricted stock. In calculating the number of performance shares and restricted stock under the Amended Agreements, the value of the performance shares granted under the Original Agreements (determined as of the date of the original awards) was first reduced by two-thirds (for the 2007-2009 performance awards) and one-third (for the

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2008-2010 performance awards). The resulting amounts were then divided by the fair market value (as defined in the Long-Term Incentive Plan) of Great Plains Energy stock on the amendment date to arrive at a number of shares, which was then divided equally between performance shares and restricted stock. The two equally weighted performance share award metrics under the Amended Agreements are funds from operations as a percentage of total adjusted debt and EPS, with the number of shares of common stock ultimately issued varying depending on Great Plains Energy's performance over stated performance periods.

The performance shares under the Amended Agreements will be re-measured at fair value each reporting period, with compensation cost to be recorded at the greater of the grant-date fair value of the Original Agreements or the fair value of the Amended Agreements for the portion for which the requisite service has been rendered. The amendment resulted in an insignificant amount of incremental compensation cost for Great Plains Energy and KCP&L.

Restricted Stock

Restricted stock cannot be sold or otherwise transferred by the recipient prior to vesting and has a value equal to the fair market value of the shares on the issue date. Restricted stock shares vest over a stated period of time with accruing reinvested dividends subject to the same restrictions. Compensation expense, calculated by multiplying shares by the grant-date fair value related to restricted stock, is recognized over the stated vesting period. Restricted stock activity for 2010 is summarized in the following table.

	Nonvested Restricted Stock	Grant Date Fair Value*
Beginning balance	612,587	\$ 20.24
Granted and issued	130,137	17.80
Vested	(291,787)	25.00
Forfeited	(44,280)	17.99
Ending balance	406,657	16.23

* weighted-average

At December 31, 2010, the remaining weighted-average contractual term was 1.2 years. The weighted-average grant-date fair value of shares granted was \$17.80 and \$14.36 during 2010 and 2009, respectively. At December 31, 2010, there was \$1.9 million of total unrecognized compensation expense, net of forfeiture rates, related to nonvested restricted stock granted under the Long-Term Incentive Plan, which will be recognized over the remaining weighted-average contractual term. The total fair value of shares vested was \$7.3 million and \$5.4 million in 2010 and 2009, respectively.

Director Deferred Share Units

Non-employee directors receive shares of Great Plains Energy's common stock as part of their annual retainer. Each director may elect to defer receipt of their shares until the end of January in the year after they leave the Board. Director Deferred Share Units have a value equal to the market value of Great Plains Energy's common stock on the grant date with accruing dividends. Compensation expense, calculated by multiplying the director deferred share units by the related grant-date fair value, is recognized at the grant date. The total fair value of shares of Director Deferred Share Units issued was insignificant for 2010 and 2009. Director Deferred Share Units activity for 2010 is summarized in the following table.

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	Share Units	Grant Date Fair Value*
Beginning balance	21,443	\$ 22.36
Issued	17,620	17.21
Ending balance	39,063	20.04

* weighted-average

10. SHORT-TERM BORROWINGS AND SHORT-TERM BANK LINES OF CREDIT

KCP&L's \$600 million revolving credit facility with a group of banks to provide support for its issuance of commercial paper and other general corporate purposes expires in August 2013. Great Plains Energy and KCP&L may transfer up to \$200 million of unused commitments between Great Plains Energy's and KCP&L's facilities. A default by KCP&L on other indebtedness totaling more than \$50.0 million is a default under the facility. Under the terms of this facility, KCP&L is required to maintain a consolidated indebtedness to consolidated capitalization ratio, as defined in the facility, not greater than 0.65 to 1.00 at all times. At December 31, 2010, KCP&L was in compliance with this covenant. At December 31, 2010, KCP&L had \$263.5 million of commercial paper outstanding, at a weighted-average interest rate of 0.41%, \$24.4 million of letters of credit outstanding and no outstanding cash borrowings under the facility. At December 31, 2009, KCP&L had \$186.6 million of commercial paper outstanding, at a weighted-average interest rate of 0.58%, \$20.9 million of letters of credit outstanding and no outstanding cash borrowings under the facility.

11. LONG-TERM DEBT

KCP&L's long-term debt is detailed in the following table.

	Year Due	December 31	
		2010	2009
(millions)			
General Mortgage Bonds			
4.90%* EIRR bonds	2012-2035	\$ 158.8	\$ 158.8
7.15% Series 2009A (8.59% rate**)	2019	400.0	400.0
4.65% EIRR Series 2005	2035	50.0	50.0
5.125% EIRR Series 2007A-1	2035	63.3	63.3
2.625% EIRR Series 2007A-2	2035	10.0	10.0
5.375% EIRR Series 2007B	2035	73.2	73.2
Senior Notes			
6.50% Series	2011	150.0	150.0
5.85% Series (5.72% rate**)	2017	250.0	250.0
6.375% Series (7.49% rate**)	2018	350.0	350.0
6.05% Series (5.78% rate**)	2035	250.0	250.0
EIRR Bonds			
4.90% Series 2008	2038	23.4	23.4
Other	2011-2018	3.3	3.5
Unamortized discount		(2.0)	(2.1)
Total		\$ 1,780.0	\$ 1,780.1

* Weighted-average interest rates at December 31, 2010

** Rate after amortizing gains/losses recognized in OCI on settlements of interest rate hedging instruments

Amortization of Debt Expense

KCP&L's amortization of debt expense was \$2.8 million and \$2.0 million for 2010 and 2009, respectively.

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KCP&L General Mortgage Bonds and EIRR Bonds

KCP&L has issued mortgage bonds under the General Mortgage Indenture and Deed of Trust dated December 1, 1986, as supplemented (Indenture). The Indenture creates a mortgage lien on substantially all of KCP&L's utility plant. Mortgage bonds totaling \$755.3 million were outstanding at December 31, 2010 and 2009.

In March 2010, KCP&L remarketed its 5.00% EIRR Series 2007A-2 general mortgage bonds maturing in 2035 totaling \$10.0 million to a new fixed rate of 2.625% from April 1, 2010, through March 31, 2011.

KCP&L Municipal Bond Insurance Policies

KCP&L's EIRR Bonds Series 2007A-1, 2007A-2 and 2007B totaling \$146.5 million are covered by a municipal bond insurance policy issued by Financial Guaranty Insurance Company (FGIC). The insurance agreement between KCP&L and FGIC provides for reimbursement by KCP&L for any amounts that FGIC pays under the municipal bond insurance policy. The policy also restricts the amount of secured debt KCP&L may issue. Because KCP&L issued debt secured by liens not permitted by the agreement or resulting in the aggregate amount of outstanding general mortgage bonds exceeding 10% of total capitalization, KCP&L was required to issue and deliver collateral to FGIC, in the form of first mortgage bonds, equal in principal amount to the principal amount of the EIRR Bonds Series 2007A-1, 2007A-2 and 2007B then outstanding. In 2009, KCP&L issued \$146.5 million of Mortgage Bonds Series 2007 EIRR Insurer due 2035 to FGIC. The bonds are not incremental debt for KCP&L but collateralize FGIC's claim on KCP&L if FGIC was required to meet its obligation under the insurance agreement.

KCP&L's secured 1992 Series EIRR bonds totaling \$31.0 million, secured Series 1993A and 1993B EIRR bonds totaling \$79.5 million, and secured and unsecured EIRR Bonds Series 2005 totaling \$35.9 million and \$50.0 million, respectively, are covered by a municipal bond insurance policy between KCP&L and Syncora Guarantee, Inc. (Syncora). The insurance agreements between KCP&L and Syncora provide for reimbursement by KCP&L for any amounts that Syncora pays under the municipal bond insurance policies. The insurance agreements contain a covenant that the indebtedness to total capitalization ratio of KCP&L and its consolidated subsidiaries will not be greater than 0.68 to 1.00. At December 31, 2010, KCP&L was in compliance with this covenant. KCP&L is also restricted from issuing additional bonds under its General Mortgage Indenture if, after giving effect to such additional bonds, the proportion of secured debt to total indebtedness would be more than 75%, or more than 50% if the long term rating for such bonds by Standard & Poor's or Moody's Investors Service would be at or below A- or A3, respectively. The insurance agreement covering the unsecured EIRR Bond Series 2005 also required KCP&L to provide collateral to Syncora in the form of \$50.0 million of Mortgage Bonds Series 2005 EIRR Insurer due 2035 for KCP&L's obligations under the insurance agreement as a result of KCP&L issuing general mortgage bonds in 2009 (other than refunding of outstanding general mortgage bonds) resulting in the aggregate amount of outstanding general mortgage bonds exceeding 10% of total capitalization. The bonds are not incremental debt for KCP&L but collateralize Syncora's claim on KCP&L if Syncora was required to meet its obligation under the insurance agreement. In the event of a default under the insurance agreements, Syncora may take any available legal or equitable action against KCP&L, including seeking specific performance of the covenants.

Scheduled Maturities

KCP&L's long-term debt maturities for the next five years are \$150.3 million in 2011, \$12.7 million in 2012, \$0.4 million in each of 2013 and 2014 and \$14.4 million in 2015.

12. COMMON SHAREHOLDERS' EQUITY

Certain conditions in the MPSC and KCC orders authorizing the Great Plains Energy holding company structure require KCP&L to maintain consolidated common equity of at least 35% of total capitalization (including only the amount of short-term debt in excess of the amount of construction work in progress). Under the Federal Power Act, KCP&L generally can pay dividends only out of retained earnings. The revolving credit agreement of KCP&L contains a covenant requiring it to maintain a consolidated indebtedness to consolidated total capitalization ratio of not more than

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0.65 to 1.00. As of December 31, 2010, all of KCP&L's retained earnings and net income were free of restrictions.

Great Plains Energy made capital contributions to KCP&L of \$247.5 million in 2009. These contributions were made to fund the Comprehensive Energy Plan projects. At December 31, 2010, KCP&L's contributions from Great Plains Energy totaled \$1,076.1 million and are reflected in other paid-in capital on the KCP&L balance sheet.

13. COMMITMENTS AND CONTINGENCIES

Environmental Matters

KCP&L is subject to extensive regulation by federal, state and local authorities with regard to environmental matters primarily through their utility operations. In addition to imposing extensive and continuing compliance obligations, laws, regulations and permits authorize the imposition of substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. The cost of complying with current and future environmental requirements is expected to be material to KCP&L. Failure to comply with environmental requirements or to timely recover environmental costs through rates could have a material adverse effect on KCP&L.

The following discussion groups environmental and certain associated matters into the broad categories of air and climate change, water, solid waste and remediation.

Air and Climate Change

The Clean Air Act and associated regulations enacted by the Environmental Protection Agency (EPA) form a comprehensive program to preserve air quality. States are required to establish regulations and programs to address all requirements of the Clean Air Act and have the flexibility to enact more stringent requirements. All of KCP&L's generating facilities, and certain of its other facilities, are subject to the Clean Air Act.

KCP&L's current estimate of capital expenditures (exclusive of AFUDC and property taxes) to comply with the currently effective Clean Air Interstate Rule (CAIR) and with the best available retrofit technology (BART) rule is approximately \$1 billion. As discussed below, CAIR has been remanded to the EPA, but remains in effect until the EPA issues final rules consistent with the court's order or until the court takes further action. In July 2010, the EPA proposed the Transport Rule to replace CAIR. However, due to uncertainties regarding the proposal (discussed below), it is not possible to predict what the final rules may be, when the rules may be issued, or the costs associated with such rules. The actual cost of compliance with any future rules, and with BART, may be significantly different from the cost estimate provided.

The potential capital costs of the Collaboration Agreement provisions (discussed below) relating to NO_x, SO₂ and particulate emission limits at the LaCygne generating station are within the disclosed overall capital cost estimate of approximately \$1 billion (discussed above). However, the estimated capital costs do not reflect potential costs relating to requirements enacted in the future, including potential requirements regarding climate change and control of mercury emissions (discussed below), and also do not reflect costs relating to additional wind generation, energy efficiency and other CO₂ emission offsets contemplated by the Collaboration Agreement or that may be required under the Missouri or Kansas renewable energy standards, which are discussed below. The estimate does not reflect the non-capital costs KCP&L incurs on an ongoing basis to comply with environmental laws, which may increase in the future due to the implementation of KCP&L's Comprehensive Energy Plan and the ongoing compliance with current or future environmental laws. KCP&L expects to seek recovery of the costs associated with the Collaboration Agreement and expects to seek recovery of the costs associated with environmental requirements through rate increases; however, there can be no assurance that such rate increases would be granted. KCP&L may be subject to materially adverse rate treatment in response to competitive, economic, political, legislative or regulatory pressures and/or public perception of KCP&L's environmental reputation.

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Clean Air Interstate Rule (CAIR) and Transport Rule

The CAIR requires reductions in SO₂ and NO_x emissions in 28 states, including Missouri. The reduction in both SO₂ and NO_x emissions is accomplished through statewide caps for NO_x and SO₂. More restrictive caps are scheduled to become effective January 1, 2015. KCP&L's fossil fuel-fired plants located in Missouri are subject to CAIR, while their fossil fuel-fired plants in Kansas are not.

On July 11, 2008, the D.C. Circuit Court of Appeals vacated CAIR in its entirety and remanded the matter to the EPA to promulgate a new rule consistent with its opinion. On December 23, 2008, the Court issued an order remanding CAIR to the EPA to revise the rule consistent with its July 2008 order. The CAIR thus remains in effect pending future EPA or court action, including the proposed Transport Rule discussed below.

CAIR currently establishes a market-based cap-and-trade program with an emission allowance allocation. Facilities demonstrate compliance with CAIR by holding sufficient allowances for each ton of SO₂ and NO_x emitted in any given year. KCP&L is currently allowed to utilize unused SO₂ emission allowances that it has either accumulated during previous years of the Acid Rain Program or purchased to meet the more stringent CAIR requirements. At December 31, 2010, KCP&L had accumulated unused SO₂ emission allowances sufficient to support over 135,000 tons of SO₂ emissions (enough to support expected requirements under the current CAIR for the foreseeable future) under the provisions of the Acid Rain program, which are recorded in inventory at zero cost. KCP&L purchases NO_x allowances as needed.

Analysis of the current CAIR rule indicates that NO_x and SO₂ control may be required for KCP&L's Montrose Station in Missouri, and control may be achieved through a combination of pollution control equipment and the use or purchase of emission allowances as needed.

In July 2010, the EPA proposed the Transport Rule to replace the current CAIR. The Transport Rule, like CAIR, will require the states within its scope to reduce power plant SO₂ and NO_x emissions that contribute to ozone and fine particle nonattainment in other states. The geographical scope of the Transport Rule is broader than CAIR, and includes Kansas in addition to Missouri and other states. The Transport Rule would also impose more stringent emissions limitations than CAIR and, unlike CAIR, would not utilize Acid Rain Program allowances for compliance. The EPA is proposing a preferred approach and is taking comment on two alternatives. In the EPA's preferred approach, the EPA would set an emissions budget for each of the affected states and the District of Columbia. The preferred approach would allow limited interstate emissions allowance trading among power plants; however, it would not permit trading of SO₂ allowances between KCP&L's Kansas and Missouri power plants. In the first alternative, the EPA is proposing to set an emissions budget for each state and allow emissions allowance trading only among power plants within a state. In the second alternative, the EPA is proposing to set an emissions budget for each state, specify the allowable emission limit for each power plant and allow some averaging. Compliance with the Transport Rule would begin in 2012. There would be additional reductions in SO₂ allowances allocable to KCP&L's Missouri power plants taking effect in 2014 pursuant to the preferred approach. There is no such additional reduction in SO₂ allowances allocable to KCP&L's Kansas power plants.

In January 2011, the EPA supplemented the record supporting the proposed Transport Rule. The EPA made available additional information relevant to the rulemaking, including, among other things, unit-level allowances for existing units calculated using two alternative methodologies and data supporting those calculations.

The proposed Transport Rule is complex and, as noted, contains alternative approaches. KCP&L is unable to predict when the Transport Rule (or other rule replacing CAIR) might be adopted, or the actual requirements of

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such rule. Preliminary analysis of the Transport Rule has raised various questions regarding the emission allowances allocation to, and the allowable emission rates for, KCP&L's power plants pursuant to the preferred approach and alternatives, which KCP&L addressed during the rule's comment period. Regardless of the resolution of those questions, KCP&L projects that it may not be allocated sufficient SO₂ or NO_x emissions allowances to cover its currently expected operations starting in 2012 pursuant to the preferred approach. Any shortfall in allocated allowances would need to be addressed through permissible allowance trading, installing additional emission control equipment, changes in plant operation, purchasing additional power in the wholesale market, or a combination of these and other alternatives. While KCP&L cannot reasonably predict at this time the impacts of the final Transport Rule, if it were finalized as currently proposed, KCP&L expects that any required capital expenditures would not exceed the \$1 billion estimate of capital expenditures (exclusive of AFUDC and property taxes) to comply with the currently effective CAIR and BART rule disclosed above. Any final rule could have a significant adverse effect on KCP&L's results of operations, financial position and cash flows.

Best Available Retrofit Technology (BART) Rule

The EPA BART rule directs state air quality agencies to identify whether visibility-reducing emissions from sources subject to BART are below limits set by the state or whether retrofit measures are needed to reduce emissions. BART applies to specific eligible facilities including KCP&L's LaCygne Nos. 1 and 2 in Kansas, KCP&L's Iatan No. 1 and KCP&L's Montrose No. 3 in Missouri. Initially, in Missouri, compliance with CAIR will be compliance with BART for individual sources. Both Missouri and Kansas have submitted BART plans to the EPA but neither Missouri nor Kansas has received EPA approval for their BART plans.

Mercury and Other Hazardous Air Pollutant Emissions

In January 2009, the EPA issued a memorandum stating that new electric steam generating units (EGUs) that began construction while the Clean Air Mercury Rule (CAMR) was effective are subject to a new source maximum achievable control technology (MACT) determination on a case-by-case basis.

In July 2009, the EPA sent letters notifying KCP&L that MACT determinations and schedules of compliance are required for coal and oil-fired EGUs that began actual construction or reconstruction after December 15, 2000, and identified Iatan No. 2 and Hawthorn No. 5 as affected EGUs. This was an outcome of the D.C. Court of Appeals' vacatur of both the CAMR and the contemporaneously promulgated rule removing EGUs from MACT requirements. KCP&L believes that Hawthorn No. 5 is not an affected EGU based on the reconstruction dates of the unit, and provided supporting documentation to the Missouri Department of Natural Resources (MDNR). It is not currently known how MACT determinations and schedules of compliance will impact the permitting or operating requirements for these two units, but it is possible a MACT determination may ultimately require additional emission control equipment and permit limits at Iatan No. 2, Hawthorn No. 5, or both.

In April 2010, the EPA, in a court approved settlement, agreed to develop MACT standards for mercury and potentially other hazardous air pollutant emissions. In the settlement agreement, the EPA agreed to propose MACT standards in March 2011 with final standards by November 2011. These MACT standards, if adopted, could impact KCP&L's new and existing facilities.

Management cannot predict the outcome of further judicial, administrative or regulatory actions or their financial or operational effects on KCP&L. Such actions could have a significant effect on KCP&L's results of operations, financial position and cash flows. Some of the control technology for SO₂ and NO_x could also aid in the control of mercury.

Industrial Boiler Rule

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In April 2010, the EPA issued a proposed rule that would set MACT standards for hazardous air pollutants from industrial boilers. The proposed rule would establish emission limits for KCP&L's new and existing units that produce steam other than for the generation of electricity. This proposed rule does not apply to KCP&L's electricity generating boilers, but would apply to auxiliary boilers at other generating facilities. The EPA finalized the rule in late February 2011. The financial and operational impacts to KCP&L, which could be material, are being evaluated but cannot be determined at this time.

Collaboration Agreement

In March 2007, KCP&L, the Sierra Club and the Concerned Citizens of Platte County entered into a Collaboration Agreement under which KCP&L agreed to pursue a set of initiatives including energy efficiency, additional wind generation, lower emission permit levels at its Iatan and LaCygne generating stations and other initiatives designed to offset CO₂ emissions. Full implementation of the terms of the Collaboration Agreement will necessitate approval from the appropriate authorities, as some of the initiatives in the agreement require regulatory approval.

In 2006, KCP&L installed 100MW of wind generation at its Spearville wind site. KCP&L agreed in the Collaboration Agreement to pursue increasing its wind generation capacity to 500MW in total by the end of 2012 with 100MW to be added by the end of 2010 and the remainder added by the end of 2012, subject to regulatory approval. In 2010, KCP&L completed a 48MW wind project adjacent to its existing Spearville wind site with wind turbines it already owned and also secured 52MW of renewable energy credits. KCP&L issued requests for proposals to add up to 100MW of wind generation in 2012 and is evaluating the proposals. KCP&L is evaluating alternatives to meet the remaining wind generation capacity requirement, including the purchase of renewable energy credits, power purchase agreements, KCP&L-built installations or some combination thereof.

KCP&L agreed in the Collaboration Agreement to seek a consent agreement, which it has done, with the Kansas Department of Health and Environment (KDHE) incorporating limits for stack particulate matter emissions, as well as limits for NO_x and SO₂ emissions at its LaCygne Station that will be below the presumptive limits under BART. KCP&L further agreed to use its best efforts to install emission control technologies to reduce those emissions from the LaCygne Station prior to the required compliance date under BART, but in no event later than June 1, 2015. KCP&L has issued requests for proposals for environmental equipment required to comply with BART at the LaCygne Station and is evaluating the responses. In February 2011, KCP&L filed a request with KCC for predetermination of the ratemaking treatment that will apply to the recovery of costs for its 50% share of the environmental equipment required to comply with BART at the LaCygne Station. The request for predetermination includes an estimated total project cost of \$1.23 billion. KCP&L's 50% share of the estimated cost is \$615 million.

In the Collaboration Agreement, KCP&L also agreed to offset an additional 711,000 tons of CO₂ by the end of 2012. KCP&L currently expects to achieve this offset through a number of alternatives, including improving the efficiency of its coal-fired units, equipping certain gas-fired units for winter operation and, if necessary, possibly reducing output of, or retiring, one or more coal-fired units.

Climate Change

KCP&L is subject to existing greenhouse gas reporting regulations and, as discussed below, will be subject to certain greenhouse gas permitting requirements starting in 2011. Management believes it is likely that additional federal or relevant state or local laws or regulations could be enacted to address global climate change. At the international level, while the United States is not a current party to the Kyoto Protocol, it has agreed to undertake certain voluntary actions under the non-binding Copenhagen Accord and pursuant to subsequent international discussions relating to climate change, including the establishment of a goal to reduce greenhouse gas emissions.

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International agreements legally binding on the United States may be reached in the future. Such new laws or regulations could mandate new or increased requirements to control or reduce the emission of greenhouse gases, such as CO₂, which are created in the combustion of fossil fuels. KCP&L's current generation capacity is primarily coal-fired and is estimated to produce about one ton of CO₂ per MWh, or approximately 21 million tons per year.

Laws have recently been passed in Missouri and Kansas, the states in which KCP&L's retail electric business operates, setting renewable energy standards, and management believes that national clean or renewable energy standards are also likely. While management believes additional requirements addressing these matters will probably be enacted, the timing, provisions and impact of such requirements, including the cost to obtain and install new equipment to achieve compliance, cannot be reasonably estimated at this time. In addition, certain federal courts have held that state and local governments and private parties have standing to bring climate change tort suits seeking company-specific emission reductions and monetary or other damages. The U.S. Supreme Court has agreed to hear an appeal of one of those suits. While KCP&L is not a party to any climate change tort suit, there is no assurance that such suits may not be filed in the future or the outcome if such suits are filed. Such requirements or litigation outcomes could have the potential for a significant financial and operational impact on KCP&L. KCP&L would seek recovery of capital costs and expenses for compliance through rate increases; however, there can be no assurance that such rate increases would be granted.

Legislation concerning the reduction of emissions of greenhouse gases, including CO₂, is being considered at the federal and state levels. The timing and effects of any such legislation cannot be determined at this time. In the absence of new Congressional mandates, the EPA is proceeding with the regulation of greenhouse gases under the existing Clean Air Act.

In May 2010, the EPA issued a final rule addressing greenhouse gas emissions from stationary sources under the Clean Air Act permitting programs. This final rule sets thresholds for greenhouse gas emissions that define when permits under the Prevention of Significant Deterioration (PSD) and Title V Operating Permit programs are required for new and existing industrial facilities. The EPA phased in the Clean Air Act permitting requirements for greenhouse gas emissions in two initial steps. In step 1, which started January 2, 2011, only sources currently subject to the PSD permitting program (i.e., those that are newly-constructed or modified in a way that significantly increases emissions of a pollutant other than greenhouse gas) are subject to Title V or PSD permitting requirements, respectively, for their greenhouse gas emissions. For these projects, only projects with new or increases of greenhouse gas emissions of 75,000 tons per year or more of total greenhouse gases, on a CO₂ equivalent basis, need to determine the best available control technology for their greenhouse gas emissions.

In addition, sources subject to the Title V Operating Permit Program need to address greenhouse gas emissions as those permits are applied for or renewed. In step 2, starting July 1, 2011, Title V and PSD permitting requirements will cover, for the first time, new construction projects that emit greenhouse gas emissions of at least 100,000 tons per year even if they do not exceed the permitting thresholds for any other pollutant. In addition, modifications at such existing facilities that increase greenhouse gas emissions by at least 75,000 tons per year will be subject to permitting requirements, even if they do not significantly increase emissions of any other pollutant. KCP&L's generating facilities that trigger these thresholds for new installations, modifications or Title V operating permits will be subject to this rule.

In December 2010, the EPA announced it entered into a proposed settlement agreement to issue a rule that will address greenhouse gas emissions from EGUs. The rule would establish new source performance standards for new and modified EGUs and emission guidelines for existing EGUs. Under the settlement agreement, the EPA

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would commit to issuing proposed regulations by July 2011, and final regulations by May 2012.

At the state level, a Kansas law enacted in May 2009 requires Kansas public electric utilities, including KCP&L, to have renewable energy generation capacity equal to at least 10% of their three-year average Kansas peak retail demand by 2011. The percentage increases to 15% by 2016 and 20% by 2020. A Missouri law enacted in November 2008 requires at least 2% of the electricity provided by Missouri investor-owned utilities (including KCP&L) to their Missouri retail customers to come from renewable resources, including wind, solar, biomass and hydropower, by 2011, increasing to 5% in 2014, 10% in 2018, and 15% in 2021, with a small portion (estimated to be about 2MW in 2011 for KCP&L) required to come from solar resources.

KCP&L projects that its current renewable resources (including accumulated renewable energy credits) will be sufficient for compliance with the Missouri requirements, exclusive of the solar requirement, through 2017. KCP&L projects that the purchase of solar renewable energy credits will be sufficient for compliance with the Missouri requirements through 2011. KCP&L has issued requests for proposals for compliance with the solar requirement beyond 2011 and is evaluating the proposals. KCP&L continues to evaluate options for compliance beyond these years.

KCP&L also projects that its current renewable resources (including accumulated renewable energy credits) combined with the 48MW wind project and 52MW of renewable energy credits discussed above will be sufficient for compliance with the 2011 Kansas requirements. KCP&L issued requests for proposals to add up to 100MW of wind generation in 2012 and is evaluating the proposals.

Additionally, in November 2007, governors from six Midwestern states, including Kansas, signed the Midwestern Greenhouse Gas Reduction Accord, which has established the goal of reducing member states' greenhouse gas emissions to 15% to 20% below 2005 levels by 2020, and 60% to 80% below 2005 levels by 2050.

Greenhouse gas legislation or regulation has the potential of having significant financial and operational impacts on KCP&L, including the potential costs and impacts of achieving compliance with limits that may be established. However, the ultimate financial and operational consequences to KCP&L cannot be determined until such legislation is passed, regulations are issued or, with respect to those regulations that have been issued, additional guidance is provided. Management will continue to monitor the progress of relevant legislation and regulations.

Ozone NAAQS

In June 2007, monitor data indicated that the Kansas City area violated the 1997 primary eight-hour ozone national ambient air quality standard (NAAQS). Missouri and Kansas have implemented the responses established in the maintenance plans for control of ozone. The responses in both states do not require additional controls at KCP&L's generation facilities beyond the currently proposed controls for CAIR and BART. The EPA has various options over and above the implementation of the maintenance plans for control of ozone to address the violation but has not yet acted. At this time, management is unable to predict how the EPA will respond or how that response will impact KCP&L's operations. However, the EPA's response could have a significant effect on KCP&L's results of operations, financial position and cash flows.

In March 2008, the EPA significantly strengthened its NAAQS for ground-level ozone. The EPA revised the primary eight-hour ozone standard, designed to protect public health, to a level of 0.075 parts per million (ppm). The EPA also strengthened the secondary eight-hour ozone standard to the level of 0.075 ppm making it identical to the revised primary standard. The previous primary and secondary standards, set in 1997, were effectively

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0.084 ppm.

In March 2009, the MDNR and KDHE submitted to the EPA their determinations that the Kansas City area is a nonattainment area under the 2008 primary eight-hour ozone standard. The EPA will make final designations of attainment and nonattainment areas. By 2013, states must submit state implementation plans outlining how states will reduce ozone to meet the standards in nonattainment areas. Although the impact on KCP&L's operations will not be known until after the final nonattainment designations and the state implementation plans are submitted, it could have a significant effect on KCP&L's results of operations, financial position and cash flows.

In January 2010, the EPA proposed to reconsider and further strengthen the 2008 NAAQS for ground-level ozone. The EPA proposed to strengthen the primary eight-hour ozone standard to a level within the range of 0.060-0.070 ppm. The EPA also proposed to establish a distinct cumulative, seasonal secondary standard, designed to protect sensitive vegetation and ecosystems, to within the range of 7-15 ppm-hours. In December 2010, the EPA filed a motion requesting court approval for additional time, until July 2011, to finalize the rule.

SO₂ NAAQS

In June 2010, the EPA strengthened the primary NAAQS for SO₂. The EPA revised the primary SO₂ standard by establishing a new 1-hour standard at a level of 0.075 ppm. The EPA revoked the two existing primary standards of 0.140 ppm evaluated over 24-hours and 0.030 ppm evaluated over an entire year. Although the impact on KCP&L's operations will not be known until after the nonattainment designations are approved and the state implementation plans submitted, it could have a significant effect on KCP&L's results of operations, financial position and cash flows.

Montrose Station Notice of Violation

In June 2009, KCP&L received notification from the MDNR alleging that its Montrose Station had excess particulate matter emissions in 2008. KCP&L is working with the MDNR to resolve this issue and management believes the outcome will have an insignificant impact to KCP&L's results of operations, financial position and cash flows.

Water

The Clean Water Act and associated regulations enacted by the EPA form a comprehensive program to preserve water quality. Like the Clean Air Act, states are required to establish regulations and programs to address all requirements of the Clean Water Act, and have the flexibility to enact more stringent requirements. All of KCP&L's generating facilities, and certain of its other facilities, are subject to the Clean Water Act.

Section 316(b) of the Clean Water Act is designed to protect aquatic life from being killed or injured by cooling water intake structures. The EPA had previously issued regulations pursuant to Section 316(b) of the Clean Water Act regarding cooling water intake structures. Subsequent to an appellate court ruling, the EPA suspended the regulations and is engaged in further rulemaking on this matter. In December 2010, in a court approved settlement, the EPA agreed to propose a new rule in March 2011 and to finalize it in July 2012. At this time, management is unable to predict how the EPA will respond or how that response will impact KCP&L's operations.

KCP&L holds a permit from the MDNR covering water discharge from its Hawthorn Station. The permit authorizes KCP&L to, among other things, withdraw water from the Missouri river for cooling purposes and return the heated water to the Missouri river. KCP&L has applied for a renewal of this permit and the EPA has submitted an interim objection letter regarding the allowable amount of heat that can be contained in the returned water. Until this matter is resolved, KCP&L continues to operate under its current permit. KCP&L cannot predict the outcome of this matter; however, while less significant outcomes are possible, this matter may require KCP&L to reduce its generation at Hawthorn Station,

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install cooling towers or both, any of which could have a significant impact on KCP&L. The outcome could also affect the terms of water permit renewals at KCP&L's Iatan Station.

Additionally, in September 2009, the EPA announced plans to revise the existing standards for water discharges from coal-fired power plants. In November 2010, the EPA filed a motion requesting court approval of a consent agreement in which the EPA agreed to propose a rule in July 2012 and to finalize it in January 2014. Until a rule is proposed and finalized, the financial and operational impacts to KCP&L cannot be determined.

Solid Waste

Solid and hazardous waste generation, storage, transportation, treatment and disposal is regulated at the federal and state levels under various laws and regulations. In May 2010, the EPA proposed to regulate coal combustion residuals (CCRs) under the Resource Conservation and Recovery Act (RCRA) to address the risks from the disposal of CCRs generated from the combustion of coal at electric generating facilities. The EPA is considering two options in this proposal. Under the first proposal, the EPA would regulate CCRs as special wastes subject to regulation under subtitle C of RCRA (hazardous), when they are destined for disposal in landfills or surface impoundments. Under the second proposal, the EPA would regulate disposal of CCRs under subtitle D of RCRA (non-hazardous). KCP&L principally uses coal in generating electricity and disposes of the CCRs in both on-site facilities and facilities owned by third parties. The proposed CCR rule has the potential of having a significant financial and operational impact on KCP&L in connection with achieving compliance with the proposed requirements. However, the financial and operational consequences to KCP&L cannot be determined until an option is selected by the EPA and the final regulation is enacted.

Remediation

Certain federal and state laws, including the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) hold current and previous owners or operators of real property, and any person who arranges for the disposal or treatment of hazardous substances at a property, liable on a joint and several basis for the costs of cleaning up contamination at or migrating from such real property, even if they did not know of and were not responsible for such contamination. CERCLA and other laws also authorize the EPA and other agencies to issue orders compelling potentially responsible parties to clean up sites that are determined to present an actual or potential threat to human health or the environment.

At December 31, 2010 and 2009, KCP&L had \$0.3 million accrued for environmental remediation expenses, which covers ground water monitoring at a former manufactured gas plant site. The amount accrued was established on an undiscounted basis and KCP&L does not currently have an estimated time frame over which the accrued amount may be paid.

In January 2010, the EPA announced an advance notice of proposed rulemaking under CERCLA identifying classes of facilities for which the EPA will develop financial assurance requirements, including the electric power generation, transmission and distribution industry. The CERCLA financial assurance would be for risks associated with KCP&L's production, transportation, treatment, storage or disposal of CERCLA hazardous substances. The impact on KCP&L cannot be determined until the regulations are finalized.

In April 2010, the EPA announced an advance notice of proposed rulemaking for the use and distribution in commerce of certain polychlorinated biphenyls (PCBs), PCB items and certain other areas of the PCB regulations. The EPA is reassessing the use, distribution in commerce, marking, and storage for reuse of liquid PCBs in electric and non-electric equipment and the use of the 50 ppm level for excluded PCB products among other things. The impact on KCP&L cannot be determined until the regulations are finalized.

Contractual Commitments

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KCP&L's expenses related to lease commitments were \$13.2 million and \$19.3 million in 2010 and 2009, respectively.

KCP&L's contractual commitments at December 31, 2010, excluding pensions and long-term debt, are detailed in the following tables.

	2011	2012	2013	2014	2015	After 2015	Total
Lease commitments				(millions)			
Operating lease	\$ 14.1	\$ 13.1	\$ 12.7	\$ 12.5	\$ 12.1	\$ 129.4	\$ 193.9
Capital lease	0.2	0.2	0.2	0.2	0.2	3.2	4.2
Purchase commitments							
Fuel	296.8	241.5	249.1	144.4	104.9	125.3	1,162.0
Purchased capacity	5.5	4.7	3.7	2.9	3.0	1.2	21.0
Other	127.5	15.0	6.0	7.3	1.9	40.8	198.5
Total contractual commitments	\$ 444.1	\$ 274.5	\$ 271.7	\$ 167.3	\$ 122.1	\$ 299.9	\$ 1,579.6

Lease commitments end in 2032. Operating lease commitments include rail cars to serve jointly-owned generating units where KCP&L is the managing partner. KCP&L will be reimbursed by the other owners for approximately \$2.0 million per year (\$13.7 million total) of the amounts included in the table above.

Fuel commitments consist of commitments for nuclear fuel, coal and coal transportation. KCP&L purchases capacity from other utilities and nonutility suppliers. Purchasing capacity provides the option to purchase energy if needed or when market prices are favorable. KCP&L has capacity sales agreements not included above that total \$6.9 million for 2011, \$3.8 million for 2012, and \$1.6 million for 2013. Other represents individual commitments entered into in the ordinary course of business.

14. LEGAL PROCEEDINGS

KCP&L Hawthorn No. 5 Litigation

KCP&L received reimbursement for the 1999 Hawthorn No. 5 boiler explosion under a property damage insurance policy with Travelers Property Casualty Company of America (Travelers). Travelers filed suit in the U.S. District Court for the Eastern District of Missouri in November 2005, against National Union Fire Insurance Company of Pittsburgh, Pennsylvania, (National Union) and KCP&L was added as a defendant in June 2006. The case was subsequently transferred to the U.S. District Court for the Western District of Missouri. Travelers sought recovery of \$10 million that KCP&L recovered through subrogation litigation. On July 24, 2008, the Court held that Travelers is not entitled to any recovery from KCP&L. Travelers appealed this decision on March 11, 2009, to the Court of Appeals for the Eighth Circuit. In September 2010, the Court of Appeals affirmed the District Court's decision. The Company does not currently expect any further action with respect to this matter.

KCP&L Spent Nuclear Fuel and Radioactive Waste

In January 2004, KCP&L and the other two Wolf Creek owners filed a lawsuit against the United States in the U.S. Court of Federal Claims seeking \$14.1 million of damages resulting from the government's failure to begin accepting spent nuclear fuel for disposal in January 1998, as the government was required to do by the Nuclear Waste Policy Act of 1982. The Wolf Creek case was tried before a U.S. Court of Federal Claims judge in June 2010, and a decision was issued in November 2010, granting KCP&L and the other two Wolf Creek owners \$10.6 million (\$5.0 million KCP&L share) in damages. In January 2011, KCP&L and the other two Wolf Creek owners as well as the United States filed appeals of the decision of the U.S. Court of Federal Claims to the U.S. Court of Appeals for the Federal Circuit.

KCP&L Advanced Coal Credit Arbitration

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In July 2009, KCP&L was served a notice to arbitrate by The Empire District Electric Company (Empire), Kansas Electric Cooperative, Inc. (KEPCO) and Missouri Joint Municipal Electric Utility Commission (MJMEUC), the non-Company joint owners of Iatan No. 2. These joint owners asserted that they were entitled to receive proportionate shares (or the monetary equivalent) of approximately \$125 million of qualifying advance coal project credits for Iatan No. 2. As independent entities, the joint owners are taxed separately and the non-Company joint owners do not dispute that they did not, in fact, apply for the credits themselves. Notwithstanding this, they contended that they should receive proportional shares of the credit. On December 30, 2009, an arbitration panel issued its order denying the KEPCO and MJMEUC claims but ordering KCP&L and Empire to jointly seek a reallocation of the tax credit from the IRS giving Empire its representative percentage of the total tax credit, worth approximately \$17.7 million. The order further specified that if the IRS denies the parties' reallocation request or if Empire is allocated less than its proportionate share of the tax credits, KCP&L will be responsible for paying Empire the full value of its representative percentage of the tax credits (less the amount of tax credits, if any, Empire ultimately receives) in cash. In September 2010, the IRS issued an amended memorandum of understanding to reallocate \$17.7 million of the original \$125 million of the advanced coal project credits to Empire, meeting the requirements of the arbitration order issued on December 30, 2009. KCP&L subsequently dismissed its March 31, 2010, appeal of the arbitration order. In 2010, KCP&L reversed a \$17.7 million liability previously recorded in other current liabilities for this matter.

Iatan Levee Litigation

On May 22, 2009, several farmers filed suit against Great Plains Energy and KCP&L in the Circuit Court of Platte County, Missouri, alleging negligence, private nuisance, trespass and violations of the Missouri Crop Protection Act and seeking unspecified compensatory and punitive damages. These allegations stem from flooding at or near the Iatan Station in 2007 and 2008. The farmers allege the flooding was a result of maintenance of a nearby levee. The petition seeks class certification from the courts. Written discovery and depositions are underway. This matter is set for trial in October 2011. Management cannot predict the outcome of this matter.

15. RELATED PARTY TRANSACTIONS AND RELATIONSHIPS

KCP&L employees manage GMO's business and operate its facilities at cost. These costs totaled \$100.9 million for 2010 and \$102.7 million for 2009. Additionally, KCP&L and GMO engage in wholesale electricity transactions with each other. KCP&L is also authorized to participate in the Great Plains Energy money pool, an internal financing arrangement in which funds may be lent on a short-term basis to KCP&L. The following table summarizes KCP&L's related party receivables and payables.

	December 31	
	2010	2009
	(millions)	
Receivable from GMO	\$ 29.6	\$ 26.4
Receivable from Receivables Company	49.6	39.8
Payable to Great Plains Energy Services Incorporated	-	(0.2)
Receivable from Great Plains Energy	13.3	15.1
Receivable from MPS Merchant	0.3	0.9

16. DERIVATIVE INSTRUMENTS

KCP&L is exposed to a variety of market risks including interest rates and commodity prices. Management has established risk management policies and strategies to reduce the potentially adverse effects that the volatility of the markets may have on KCP&L's operating results. Commodity risk management activities, including the use of certain derivative instruments, are subject to the management, direction and control of an internal risk management committee. Management's interest rate risk management strategy uses derivative instruments to adjust KCP&L's liability portfolio to

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optimize the mix of fixed and floating rate debt within an established range. In addition, KCP&L uses derivative instruments to hedge against future interest rate fluctuations on anticipated debt issuances. Management maintains commodity price risk management strategies that use derivative instruments to reduce the effects of fluctuations in fuel expense caused by commodity price volatility. Counterparties to commodity derivatives and interest rate swap agreements expose KCP&L to credit loss in the event of nonperformance. This credit loss is limited to the cost of replacing these contracts at current market rates. Derivative instruments, excluding those instruments that qualify for the NPNS election, which are accounted for by accrual accounting, are recorded on the balance sheet at fair value as an asset or liability. Changes in the fair value of derivative instruments are recognized currently in net income unless specific hedge accounting criteria are met.

KCP&L has posted collateral, in the ordinary course of business, for the aggregate fair value of all derivative instruments with credit risk-related contingent features that are in a liability position. At December 31, 2010, KCP&L has posted collateral in excess of the aggregate fair value of its derivative instruments; therefore, if the credit risk-related contingent features underlying these agreements were triggered, KCP&L would not be required to post additional collateral to its counterparties.

The Dodd-Frank Wall Street Reform and Consumer Protection Act, signed into law in July 2010, includes provisions related to the swaps and over-the-counter derivative markets. KCP&L currently expects that its commodity and interest rate hedges will be exempt from mandatory clearing and exchange trading requirements. Capital and margin requirements for these hedges are expected to be determined over the next year as regulatory agencies implement rules. While KCP&L currently does not anticipate this law and the associated regulatory rules to have a material impact on its financial condition, the ultimate impact cannot be reasonably determined until the final rules are issued.

Commodity Risk Management

KCP&L's risk management policy is to use derivative instruments to mitigate its exposure to market price fluctuations on a portion of its projected natural gas purchases to meet generation requirements for retail and firm wholesale sales. At December 31, 2010, KCP&L has hedged 66%, 45% and 22%, respectively, of the 2011, 2012 and 2013 projected natural gas usage for retail load and firm MWh sales, primarily by utilizing futures contracts and financial instruments. The fair values of these instruments are recorded as derivative assets or liabilities with an offsetting entry to OCI for the effective portion of the hedge. To the extent the hedges are not effective, any ineffective portion of the change in fair market value would be recorded currently in fuel expense. KCP&L has not recorded any ineffectiveness on natural gas hedges in 2010 or 2009.

The notional and recorded fair values of KCP&L's open positions for derivative instruments are summarized in the following table. The fair values of these derivatives are recorded on the balance sheet. The fair values below are gross values before netting agreements and netting of cash collateral.

	December 31			
	2010		2009	
	Notional Contract Amount	Fair Value	Notional Contract Amount	Fair Value
	(millions)			
Futures contracts				
Cash flow hedges	\$ 4.0	\$ -	\$ 3.2	\$ -
Option contracts				
Cash flow hedges	-	-	2.3	0.2

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The fair value of KCP&L's open derivative positions are summarized in the following table. The table contains derivative instruments designated as hedging instruments under GAAP. The fair values below are gross values before netting agreements and netting of cash collateral.

December 31, 2010	Balance Sheet Classification	Asset Derivatives Fair Value	Liability Derivatives Fair Value
(millions)			
Derivatives Designated as Hedging Instruments			
Commodity contracts	Derivative instruments	\$ 0.1	\$ 0.1
December 31, 2009			
Derivatives Designated as Hedging Instruments			
Commodity contracts	Derivative instruments	\$ 0.4	\$ 0.2

The following tables summarize the amount of gain (loss) recognized in OCI or earnings for interest rate and commodity hedges.

Derivatives in Cash Flow Hedging Relationship			
		Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)	
	Amount of Gain (Loss) Recognized in OCI on Derivatives (Effective Portion)	Income Statement Classification	Amount
2010	(millions)		(millions)
Interest rate contracts	\$ -	Interest charges	\$ (8.8)
Commodity contracts	(0.9)	Fuel	(0.5)
Income tax benefit (expense)	0.3	Income tax benefit (expense)	3.6
Total	\$ (0.6)	Total	\$ (5.7)
2009			
Interest rate contracts	\$ 1.0	Interest charges	\$ (7.5)
Commodity contracts	(0.8)	Fuel	(1.1)
Income tax benefit (expense)	(0.1)	Income tax benefit (expense)	3.3
Total	\$ 0.1	Total	\$ (5.3)

The amounts recorded in accumulated OCI related to the cash flow hedges are summarized in the following table.

	December 31	
	2010	2009
	(millions)	
Current assets	\$ 12.0	\$ 13.3
Current liabilities	(71.6)	(81.2)
Deferred income taxes	23.2	26.4
Total	\$ (36.4)	\$ (41.5)

KCP&L's accumulated OCI includes \$8.8 million that is expected to be reclassified to expense over the next twelve

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months.

17. FAIR VALUE MEASUREMENTS

GAAP defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. GAAP establishes a fair value hierarchy, which prioritizes the inputs to valuation techniques used to measure fair value into three broad categories, giving the highest priority to quoted prices in active markets for identical assets or liabilities and lowest priority to unobservable inputs. A definition of the various levels, as well as discussion of the various measurements within the levels, is as follows:

Level 1 – Unadjusted quoted prices for identical assets or liabilities in active markets that KCP&L has access to at the measurement date. Assets categorized within this level consist of KCP&L’s various exchange traded derivative instruments and equity and U.S. Treasury securities that are actively traded within KCP&L’s decommissioning trust fund.

Level 2 – Market-based inputs for assets or liabilities that are observable (either directly or indirectly) or inputs that are not observable but are corroborated by market data. Assets and liabilities categorized within this level consist of KCP&L’s various non-exchange traded derivative instruments traded in over-the-counter markets and certain debt securities within KCP&L’s decommissioning trust fund.

Level 3 – Unobservable inputs, reflecting KCP&L’s own assumptions about the assumptions market participants would use in pricing the asset or liability. Assets categorized within this level consist of certain debt securities within KCP&L’s decommissioning trust fund for which sufficiently observable market data is not available to corroborate the valuation inputs.

The following tables include KCP&L’s balances of financial assets and liabilities measured at fair value on a recurring basis at December 31, 2010 and 2009.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report 2010/Q4
Kansas City Power & Light Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Description	Fair Value Measurements Using				
	December 31 2010	Netting ^(c)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Assets			(millions)		
Derivative instruments ^(a)	\$ -	\$ (0.1)	\$ 0.1	\$ -	\$ -
Nuclear decommissioning trust ^(b)					
Equity securities	85.5	-	85.5	-	-
Debt securities					
U.S. Treasury	8.9	-	8.9	-	-
U.S. Agency	4.8	-	-	4.8	-
State and local obligations	2.5	-	-	2.5	-
Corporate bonds	23.7	-	-	23.7	-
Foreign governments	0.7	-	-	0.7	-
Other	0.4	-	-	0.4	-
Total nuclear decommissioning trust	126.5	-	94.4	32.1	-
Total	126.5	(0.1)	94.5	32.1	-
Liabilities					
Derivative instruments ^(a)	-	(0.1)	0.1	-	-
Total	\$ -	\$ (0.1)	\$ 0.1	\$ -	\$ -

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NOTES TO FINANCIAL STATEMENTS (Continued)			

Description	December 31 2009	Netting ^(c)	Fair Value Measurements Using		
			Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
(millions)					
Assets					
Derivative instruments ^(a)	\$ 0.2	\$ (0.2)	\$ 0.2	\$ 0.2	\$ -
Nuclear decommissioning trust ^(b)					
Equity securities	44.5	-	44.5	-	-
Debt securities					
U.S. Treasury	11.2	-	11.2	-	-
U.S. Agency	3.5	-	-	3.5	-
State and local obligations	3.1	-	-	2.9	0.2
Corporate bonds	18.9	-	-	18.9	-
Foreign governments	0.7	-	-	0.7	-
Other	1.2	-	-	1.2	-
Total nuclear decommissioning trust	83.1	-	55.7	27.2	0.2
Total	83.3	(0.2)	55.9	27.4	0.2
Liabilities					
Derivative instruments ^(a)	-	(0.2)	-	0.2	-
Total	\$ -	\$ (0.2)	\$ -	\$ 0.2	\$ -

- (a) The fair value of derivative instruments is estimated using market quotes, over-the-counter forward price and volatility curves and correlations among fuel prices, net of estimated credit risk.
- (b) Fair value is based on quoted market prices of the investments held by the fund and/or valuation models. The total does not include \$2.7 million and \$29.4 million at December 31, 2010 and 2009, respectively, of cash and cash equivalents, which are not subject to the fair value requirements.
- (c) Represents the difference between derivative contracts in an asset or liability position presented on a net basis by counterparty on the balance sheet where a master netting agreement exists between the Company and the counterparty.

The following tables reconcile the beginning and ending balances for all level 3 assets and liabilities, net measured at fair value on a recurring basis for 2010 and 2009.

Fair Value Measurements Using Significant Unobservable Inputs (Level 3)	
	State & Local Obligations
	(millions)
Balance January 1, 2010	\$ 0.2
Sales	(0.2)
Balance December 31, 2010	\$ -

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NOTES TO FINANCIAL STATEMENTS (Continued)			

Fair Value Measurements Using Significant Unobservable Inputs (Level 3)

Description	U.S. Agency	State & Local Obligations	Mortgage	Total
			Backed Securities	
(millions)				
Balance January 1, 2009	\$ 3.9	\$ -	\$ 2.9	\$ 6.8
Total realized/unrealized gains or (losses)				
Included in regulatory liability	-	-	1.1	1.1
Purchase, issuances, and settlements	(3.9)	-	(4.0)	(7.9)
Transfers in and/or out of Level 3	-	0.2	-	0.2
Balance December 31, 2009	\$ -	\$ 0.2	\$ -	\$ 0.2

18. TAXES

Components of income tax expense are detailed in the following table.

	2010	2009
Current income taxes	(millions)	
Federal	\$ 3.7	\$ 39.3
State	0.8	4.4
Total	4.5	43.7
Deferred income taxes		
Federal	69.8	(41.6)
State	13.3	3.6
Total	83.1	(38.0)
Noncurrent income taxes		
Federal	(1.6)	3.4
State	(0.2)	(0.1)
Total	(1.8)	3.3
Investment tax credit		
Deferral	(4.2)	37.2
Amortization	(2.1)	(1.4)
Total	(6.3)	35.8
Total	\$ 79.5	\$ 44.8

Income Tax Expense and Effective Income Tax Rates

Income tax expense and the effective income tax rates reflected in the financial statements and the reasons for their differences from the statutory federal rates are detailed in the following table.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report 2010/Q4
Kansas City Power & Light Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

	Income Tax Expense		Income Tax Rate	
	2010	2009	2010	2009
	(millions)			
Federal statutory income tax	\$ 83.8	\$ 59.6	35.0 %	35.0 %
Differences between book and tax depreciation not normalized	(4.5)	(7.7)	(1.9)	(4.5)
Amortization of investment tax credits	(2.1)	(1.4)	(0.9)	(0.8)
Federal income tax credits	(8.5)	(7.8)	(3.5)	(4.6)
State income taxes	8.7	5.5	3.6	3.3
Medicare Part D subsidy legislation	2.8	-	1.2	-
Changes in uncertain tax positions, net	-	(0.5)	-	(0.3)
Other	(0.7)	(2.9)	(0.3)	(1.8)
Total	\$ 79.5	\$ 44.8	33.2 %	26.3 %

Deferred Income Taxes

The tax effects of major temporary differences resulting in deferred income tax assets (liabilities) in the balance sheet are in the following tables.

December 31	2010	2009
Current deferred income taxes	(millions)	
Other	\$ 5.0	\$ (0.3)
Net current deferred income tax asset (liability)	5.0	(0.3)
Noncurrent deferred income taxes		
Plant related	(708.2)	(627.7)
Income taxes on future regulatory recoveries	(117.2)	(77.6)
Derivative instruments	34.4	37.4
Pension and postretirement benefits	2.0	6.5
SO ₂ emission allowance sales	33.4	34.5
Fuel clause adjustments	(3.2)	0.2
Transition costs	(11.4)	(11.4)
Tax credit carryforwards	101.5	97.6
Customer demand programs	(17.3)	(13.8)
Net operating loss carryforward	1.1	0.6
Uncertain tax positions	(18.8)	(20.5)
Other	(3.8)	(2.4)
Net noncurrent deferred tax liability	(707.5)	(576.6)
Net deferred income tax liability	\$ (702.5)	\$ (576.9)

December 31	2010	2009
	(millions)	
Gross deferred income tax assets	\$ 605.1	\$ 597.3
Gross deferred income tax liabilities	(1,307.6)	(1,174.2)
Net deferred income tax liability	\$ (702.5)	\$ (576.9)

Tax Credit Carryforwards

At December 31, 2010 and 2009, KCP&L had \$101.5 million and \$97.6 million, respectively, of federal general business

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NOTES TO FINANCIAL STATEMENTS (Continued)			

income tax credit carryforwards. The carryforwards for KCP&L relate primarily to Advanced Coal Investment Tax Credits and Wind Production tax credits and expire in years 2028 to 2030.

Advanced Coal Credit

In April 2008, KCP&L was notified that its application filed in 2007 for \$125.0 million in advanced coal investment tax credits (ITC) was approved by the IRS. The credit is based on the amount of expenses incurred on the construction of Iatan No. 2. Additionally, in order to meet the advanced clean coal standards and avoid forfeiture and/or the recapture of tax credits in the future, KCP&L must meet or exceed certain environmental performance standards for at least five years once the plant is placed in service.

In September 2010, the IRS issued an amended memorandum of understanding to reallocate \$17.7 million of the original \$125 million of the advanced coal project credits to Empire, meeting the requirements of an arbitration order issued on December 30, 2009. See Note 14 for the related legal proceeding. As a result, KCP&L reduced the amount of advanced coal credit previously recognized. The amount of deferred federal tax expense associated with the reduction in 2010 was \$4.2 million. Since the tax laws require KCP&L to reduce income tax expense for ratemaking and financial statement purposes ratably over the life of the plant, KCP&L concurrently recognized a separate deferred advanced coal ITC benefit to offset the current and deferred federal tax expense. KCP&L recognized \$0.7 million of ITC in 2010 after the plant was placed in service and will continue to recognize the tax benefits over the life of the plant. At December 31, 2010, KCP&L had \$106.6 million of deferred advanced coal ITC.

Uncertain Tax Positions

At December 31, 2010 and 2009, KCP&L had \$19.1 and \$20.9 million, respectively, of liabilities related to unrecognized tax benefits. Of these amounts, \$0.3 million at December 31, 2010, and \$0.4 million at December 31, 2009, are expected to impact the effective tax rate if recognized. The \$1.8 million decrease in unrecognized tax benefits is primarily due to a \$2.6 million decrease as a result of the settlements of the IRS audit for the Great Plains Energy consolidated 2005 tax year.

The following table reflects activity for KCP&L related to the liability for unrecognized tax benefits.

	2010	2009
	(millions)	
Balance at January 1	\$ 20.9	\$ 17.6
Additions for current year tax positions	1.3	3.9
Additions for prior year tax positions	1.5	3.0
Reductions for prior year tax positions	(1.6)	(0.8)
Settlements	(2.9)	(2.2)
Statute expirations	(0.1)	(0.6)
Balance at December 31	\$ 19.1	\$ 20.9

KCP&L recognizes interest accrued related to unrecognized tax benefits in interest expense and penalties in non-operating expenses. KCP&L had accrued interest related to unrecognized tax benefits of \$1.4 million and \$1.7 million at December 31, 2010 and 2009, respectively. Amounts accrued for penalties with respect to unrecognized tax benefits for KCP&L are insignificant. In 2010, KCP&L recognized a reduction of \$0.3 million of interest expense.

The IRS is currently auditing Great Plains Energy and its subsidiaries for the 2006-2008 tax years. KCP&L estimates that it is reasonably possible that \$12.2 million of unrecognized tax benefits may be recognized in the next twelve months due to statute expirations or settlement agreements with tax authorities.

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NOTES TO FINANCIAL STATEMENTS (Continued)			

19. JOINTLY OWNED ELECTRIC UTILITY PLANTS

KCP&L's share of jointly owned electric utility plants at December 31, 2010, is detailed in the following table.

	Wolf Creek Unit	LaCygne Units	Iatan No. 1 Unit	Iatan No. 2 Unit	Iatan Common
	(millions, except MW amounts)				
KCP&L's share	47%	50%	70%	55%	61%
Utility plant in service	\$ 1,423.7	\$ 410.5	\$ 514.1	\$ 973.0	\$ 255.0
Accumulated depreciation	778.2	298.0	196.3	56.4	13.9
Nuclear fuel, net	79.2	-	-	-	-
Construction work in progress	75.3	48.1	14.5	7.1	14.4
2011 accredited capacity-MW s	560	709	494	465	NA

Each owner must fund its own portion of the plant's operating expenses and capital expenditures. KCP&L's share of direct expenses is included in the appropriate operating expense classifications in KCP&L's financial statements.

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1	(46,923,957)	(21,336)	(46,945,293)		
2	4,587,101	686,856	36,537,583		
3	610,625	(473,139)	(31,126,140)		
4	5,197,726	213,717	5,411,443	128,890,834	134,302,277
5	(41,726,231)	192,381	(41,533,850)		
6	(41,726,231)	192,381	(41,533,850)		
7	5,335,093	327,363	36,234,496		
8		(530,548)	(31,102,588)		
9	5,335,093	(203,185)	5,131,908	163,228,391	168,360,299
10	(36,391,138)	(10,804)	(36,401,942)		

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FOOTNOTE DATA			

Schedule Page: 122(a)(b) Line No.: 7 Column: e

The recognition requirements of ASC 715 "Compensation-Retirement Benefits" results in recording unamortized transition costs, prior service costs and gains/losses for the pension and other post-retirement plans to accumulated other comprehensive income. In accordance with ASC 980 "Regulated Operations," these costs were transferred to a regulatory asset.

Schedule Page: 122(a)(b) Line No.: 8 Column: e

The recognition requirements of ASC 715 "Compensation-Retirement Benefits" results in recording unamortized transition costs, prior service costs and gains/losses for the pension and other post-retirement plans to accumulated other comprehensive income. In accordance with ASC 980 "Regulated Operations," these costs were transferred to a regulatory asset.

Schedule Page: 122(a)(b) Line No.: 8 Column: g

Natural gas cash flow hedges for production fuel. As of December 31, 2010, KCP&L has hedged 66%, 45% and 22%, respectively, of the 2011, 2012 and 2013 projected natural gas usage for retail load and firm MWh sales.

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION, AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	7,529,879,771	7,529,879,771
4	Property Under Capital Leases	2,106,928	2,106,928
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	7,531,986,699	7,531,986,699
9	Leased to Others		
10	Held for Future Use	8,939,236	8,939,236
11	Construction Work in Progress	227,542,942	227,542,942
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	7,768,468,877	7,768,468,877
14	Accum Prov for Depr, Amort, & Depl	3,104,681,195	3,104,681,195
15	Net Utility Plant (13 less 14)	4,663,787,682	4,663,787,682
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	2,974,942,605	2,974,942,605
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	129,738,590	129,738,590
22	Total In Service (18 thru 21)	3,104,681,195	3,104,681,195
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	3,104,681,195	3,104,681,195

Name of Respondent
Kansas City Power & Light Company

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
04/15/2011

Year/Period of Report
End of 2010/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION, AMORTIZATION AND DEPLETION

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
					4
					5
					6
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					31
					32
					33

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year
			Additions (c)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication		
3	Nuclear Materials	4,728,143	34,511,776
4	Allowance for Funds Used during Construction	4,828,827	1,166,597
5	(Other Overhead Construction Costs, provide details in footnote)	2,633,238	501,290
6	SUBTOTAL (Total 2 thru 5)	12,190,208	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		39,537,985
9	In Reactor (120.3)	78,870,218	
10	SUBTOTAL (Total 8 & 9)	78,870,218	
11	Spent Nuclear Fuel (120.4)	83,085,759	
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	105,975,785	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	68,170,400	
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance End of Year (f)	Line No.
Amortization (d)	Other Reductions (Explain in a footnote) (e)		
			1
			2
	39,537,985	-298,066	3
		5,995,424	4
		3,134,528	5
		8,831,886	6
			7
		39,537,985	8
		78,870,218	9
		118,408,203	10
		83,085,759	11
			12
	-25,117,454	131,093,239	13
		79,232,609	14
			15
			16
			17
			18
			19
			20
			21
			22

Name of Respondent Kansas City Power & Light Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report 2010/Q4
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Other Reductions include fabricated assemblies transferred to stock (120.2) of \$39,537,985 for refueling #18, and fuel purchases of \$645,802 for refueling #18 transferred to stock (120.2).

Schedule Page: 202 Line No.: 5 Column: c

Other includes labor and overhead costs of \$357,492, travel expenses of \$7,021, and consultant charges of \$136,777.

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	72,186	
3	(302) Franchises and Consents	22,937	
4	(303) Miscellaneous Intangible Plant	147,026,511	27,595,102
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	147,121,634	27,595,102
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	8,782,031	633,186
9	(311) Structures and Improvements	165,195,654	105,880,951
10	(312) Boiler Plant Equipment	1,263,089,384	798,593,292
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	246,634,101	107,141,640
13	(315) Accessory Electric Equipment	154,354,647	42,714,182
14	(316) Misc. Power Plant Equipment	32,698,482	4,283,193
15	(317) Asset Retirement Costs for Steam Production	17,753,807	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,888,508,106	1,059,246,444
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	3,411,585	
19	(321) Structures and Improvements	420,636,431	258,783
20	(322) Reactor Plant Equipment	573,786,868	2,699,083
21	(323) Turbogenerator Units	175,202,149	38,174
22	(324) Accessory Electric Equipment	132,250,559	22,311
23	(325) Misc. Power Plant Equipment	72,275,527	6,505,031
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	1,377,563,119	9,523,382
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights		
28	(331) Structures and Improvements		
29	(332) Reservoirs, Dams, and Waterways		
30	(333) Water Wheels, Turbines, and Generators		
31	(334) Accessory Electric Equipment		
32	(335) Misc. Power PLant Equipment		
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)		
36	D. Other Production Plant		
37	(340) Land and Land Rights	1,102,201	
38	(341) Structures and Improvements	8,044,357	679,724
39	(342) Fuel Holders, Products, and Accessories	10,927,857	985,328
40	(343) Prime Movers		
41	(344) Generators	427,244,418	97,304,247
42	(345) Accessory Electric Equipment	21,561,839	406,372
43	(346) Misc. Power Plant Equipment		
44	(347) Asset Retirement Costs for Other Production	3,056,058	1,993,099
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	471,936,730	101,368,770
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	3,738,007,955	1,170,138,596

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	24,717,984	2,014,398
49	(352) Structures and Improvements	4,747,967	83,120
50	(353) Station Equipment	131,973,207	22,516,338
51	(354) Towers and Fixtures	4,068,897	244,906
52	(355) Poles and Fixtures	103,847,030	7,925,679
53	(356) Overhead Conductors and Devices	93,616,876	4,981,814
54	(357) Underground Conduit	3,233,056	305,795
55	(358) Underground Conductors and Devices	2,899,910	
56	(359) Roads and Trails		
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	369,104,927	38,072,050
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	24,794,858	17,054
61	(361) Structures and Improvements	11,465,365	117,330
62	(362) Station Equipment	160,734,058	13,308,139
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	247,763,616	5,069,089
65	(365) Overhead Conductors and Devices	199,973,535	4,348,270
66	(366) Underground Conduit	206,391,545	14,597,090
67	(367) Underground Conductors and Devices	391,550,280	18,470,709
68	(368) Line Transformers	240,600,701	7,702,402
69	(369) Services	88,544,722	5,501,792
70	(370) Meters	87,810,960	4,772,352
71	(371) Installations on Customer Premises	11,471,734	449,612
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	35,375,240	1,761,224
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,706,476,614	76,115,063
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	2,326,521	
87	(390) Structures and Improvements	90,602,482	7,717,902
88	(391) Office Furniture and Equipment	19,017,989	1,153,108
89	(392) Transportation Equipment	41,511,438	2,507,845
90	(393) Stores Equipment	957,422	1,579
91	(394) Tools, Shop and Garage Equipment	3,834,051	453,605
92	(395) Laboratory Equipment	5,561,648	505,302
93	(396) Power Operated Equipment	15,666,940	7,586,604
94	(397) Communication Equipment	107,978,371	5,476,360
95	(398) Miscellaneous Equipment	470,130	26,250
96	SUBTOTAL (Enter Total of lines 86 thru 95)	287,926,992	25,428,555
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant		
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	287,926,992	25,428,555
100	TOTAL (Accounts 101 and 106)	6,248,638,122	1,337,349,366
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	6,248,638,122	1,337,349,366

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)	Line No.
				47
			26,732,382	48
8,727			4,822,360	49
589,032		-14,476	153,886,037	50
25,892			4,287,911	51
14,449			111,758,260	52
23,507		-1	98,575,182	53
			3,538,851	54
			2,899,910	55
				56
				57
661,607		-14,477	406,500,893	58
				59
		1	24,811,913	60
11,785		-246,625	11,324,285	61
1,586,615		14,476	172,470,058	62
				63
626,549			252,206,156	64
1,096,301			203,225,504	65
101,886			220,886,749	66
4,077,956			405,943,033	67
1,596,753			246,706,350	68
174,414			93,872,100	69
355,734		1	92,227,579	70
25,091			11,896,255	71
				72
630,713			36,505,751	73
				74
10,283,797		-232,147	1,772,075,733	75
				76
				77
				78
				79
				80
				81
				82
				83
				84
				85
13,734			2,312,787	86
699,786		246,623	97,867,221	87
955,681		-3,092,264	16,123,152	88
1,422,002		-1,482,368	41,114,913	89
		1	959,002	90
			4,287,656	91
		-1	6,066,949	92
1,192,197		1,482,369	23,543,716	93
9,476,020		-1,133,751	102,844,960	94
1,327		-1,563	493,490	95
13,760,747		-3,980,954	295,613,846	96
				97
				98
13,760,747		-3,980,954	295,613,846	99
51,880,139		-4,227,578	7,529,879,771	100
				101
				102
				103
51,880,139		-4,227,578	7,529,879,771	104

Name of Respondent Kansas City Power & Light Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Schedule Page: 204 Line No.: 88 Column: f
 Transfer of office equipment and furniture \$4,226,015 to NonUtility account 121003.

Schedule Page: 204 Line No.: 95 Column: f
 Transfer of miscellaneous equipment \$1,563 to NonUtility account 121003.

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1	None				
2					
3					
4					
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6					
7					
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46					
47	TOTAL				

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

- Report separately each property held for future use at end of the year having an original cost of \$250,000 or more. Group other items of property held for future use.
- For property having an original cost of \$250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2				
3	Land for Hawthorn Ash Pond Expansion in	1996		3,651,071
4	Jackson Co., Missouri			
5				
6	Site of future Ash Pond at Iatan Station in	1998		502,529
7	Platte Co., Missouri			
8				
9	KCPL Campus Land 50 Hwy & I-470	2008		3,002,060
10				
11	Purchase Land for Hillsdale Substation	2005		574,310
12	20 Acres - Tract #347 NE 1/4 Sect 14			
13				
14	Land for Charlotte Sub#141	2007		648,226
15	NE corner of 6th & Charlotte			
16				
17	Property with original cost of less than \$250,000			561,040
18				
19				
20				
21	Other Property:			
22				
23				
24				
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45				
46				
47	Total			8,939,236

Name of Respondent Kansas City Power & Light Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Schedule Page: 214 Line No.: 17 Column: d

Per Docket No. ER10-230-000, FERC transmission formula rate, additional detail for Account 105000 has been provided below:

Sub-0149-Ridgeview Substation (Case No. ER10-230-000, Sch A-11)	\$56,110.00
All other Property with original cost of less than \$250,000	<u>\$504,930.65</u>
Total Property with original cost less than \$250,000	<u>\$561,040.65</u>

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or \$1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Purchase Land for Troost Substation	1,109,898
2	Dynamic Voltage Control	1,661,552
3	Highway Relocation - Holmes Road to Blue River Road	1,794,379
4	Replace 7.5 MVA Transformer - Holly Substation #107	1,042,320
5	Hawthorn Unit 6 Stationary Blades Replacement	7,139,994
6	Site Finishing - Iatan Common	4,789,319
7	Route 45 Bridge Replacement - Loan Agreement	2,445,849
8	Permanent Auxiliary Boiler - Iatan Common	2,670,859
9	Iatan 1 Building Modification	2,088,219
10	Replace 41 Secondary Superheater Pendants	1,962,509
11	Purchase GSU Transformer - Iatan 1	4,582,420
12	NFPA 70E Compliance	1,245,007
13	LaCygne 1 Environmental Upgrade	5,461,951
14	LaCygne 1 Cyclone Replacement	13,167,353
15	LaCygne 1 Furnace Wall and Floor Replacement	2,267,905
16	LaCygne 1 Horizontal Reheater and Primary Superheater Replacement	6,059,875
17	LaCygne 1 Hot Reheat Steam Line Replacement	3,316,635
18	Cedar Niles - Quarry 161KV Transmission Line	1,543,973
19	Rebuild Merriam-Roeland Park 161 KV Transmission Line	1,834,510
20	CIS Software Enhancements	4,314,012
21	Wolf Creek - Secondary Side Upgrade	51,424,613
22	Wolf Creek - Turbine Supervisory Instrumentation	5,226,562
23	Wolf Creek - Thermocouple Core Monitoring System Replacement	1,150,790
24	Wolf Creek - Site Security Modification	1,224,165
25	Wolf Creek - ETAP Power System Analysis Software	2,824,815
26	Wolf Creek - Reactor Head Vessel Forging	2,403,630
27	Misc Projects Under \$1,000,000	92,789,828
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
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41		
42		
43	TOTAL	227,542,942

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	2,782,078,073	2,782,078,073		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	170,793,850	170,793,850		
4	(403.1) Depreciation Expense for Asset Retirement Costs	1,077,334	1,077,334		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	2,571,243	2,571,243		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	85,048,807	85,048,807		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	259,491,234	259,491,234		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	51,035,782	51,035,782		
13	Cost of Removal	9,723,267	9,723,267		
14	Salvage (Credit)	8,283,125	8,283,125		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	52,475,924	52,475,924		
16	Other Debit or Cr. Items (Describe, details in footnote):	-2,110,747	-2,110,747		
17	Net Change in Retirement Workorders	-12,040,031	-12,040,031		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	2,974,942,605	2,974,942,605		

Section B. Balances at End of Year According to Functional Classification

20	Steam Production	993,725,433	993,725,433		
21	Nuclear Production	760,538,691	760,538,691		
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	165,849,759	165,849,759		
25	Transmission	173,587,572	173,587,572		
26	Distribution	655,268,820	655,268,820		
27	Regional Transmission and Market Operation				
28	General	225,972,330	225,972,330		
29	TOTAL (Enter Total of lines 20 thru 28)	2,974,942,605	2,974,942,605		

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report 2010/Q4
Kansas City Power & Light Company			
FOOTNOTE DATA			

Schedule Page: 219 Line No.: 8 Column: c

Pursuant to an order and agreement with the MPSC, KCP&L is to accrue additional depreciation annually through the end of the Regulatory Plan. The amount accrued in 2010 was \$42,402,888.

Pursuant to an order and agreement with the Kansas Commission, KCP&L is to accrue additional depreciation annually through the end of the Regulatory Plan. The amount accrued in 2010 was \$30,250,000.

Pursuant to an order with the MPSC, KCP&L is to record to regulatory asset account 182 the depreciation expense relating to costs for the Iatan 1 AQCS and Common projects that are not yet in rate base. The amount recorded for 2010 was \$3,204,889.

Pursuant to an order with the MPSC, KCP&L is to record to regulatory asset account 182 the depreciation expense relating to costs for the Iatan 2 projects that are not yet in rate base. The amount recorded for 2010 was \$6,931,353.

Pursuant to an order with the Kansas Commission, KCP&L is the record to regulatory account 182 depreciation expense relating to costs for the Iatan 1 AQCS and Common projects that are not yet in rate base. The amount recorded for 2010 was \$1,328,760.

The provision for Unit Trains, \$930,917, is charged to Fuel Inventory.

Schedule Page: 219 Line No.: 12 Column: c

Book cost of plant retired shown is \$844,357 less that total retirements shown on Page 207, Line 104, column (d), because Page 219 is only for Account 108, which does not include retirements for intangibles, software, land rights, or leasehold improvements accounted for in Account 111.

Schedule Page: 219 Line No.: 16 Column: c

In 2010, activity affecting the Reserve that did not run through the provision are as follows:

Reserve decreased by \$2,258,913 for transfer of office furniture and equipment to non-utility.

Reserve decreased by \$52,941 for gain recognized on sale of land.

Reserve increased by \$201,107 for transfer of office furniture from KLT Services, Inc. 04/2010.

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	Kansas City Power & Light Receivables Company			3,000,000
2	Income (Loss) from Subsidiary			779,947
3				
4				
5				
6				
7				
8				
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41				
42	Total Cost of Account 123.1 \$	0	TOTAL	3,779,947

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
		3,000,000		1
3,331,378		4,111,324		2
				3
				4
				5
				6
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				41
3,331,378		7,111,324		42

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.

2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	45,596,392	44,875,683	
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	29,900,506	31,395,137	
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	46,163,766	52,095,243	
8	Transmission Plant (Estimated)	102,050	98,559	
9	Distribution Plant (Estimated)	1,689,895	2,387,906	
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)			
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	77,856,217	85,976,845	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	6,949,219	8,433,844	
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	130,401,828	139,286,372	

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report 2010/Q4
Kansas City Power & Light Company			
FOOTNOTE DATA			

Schedule Page: 227 Line No.: 5 Column: b

Per Docket No. ER10-230-000, FERC transmission formula rate, additional detail for materials and supplies assigned to construction has been provided below:

Assigned to Construction (Estimated)	2009	2010
Production Plant (Estimated)	12,525,460	15,655,766
Transmission Plant (Estimated)	1,056,838	2,107,683
Distribution Plant (Estimated)	<u>16,318,208</u>	<u>13,631,688</u>
Total	29,900,506	31,395,137

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year		2011	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	232,527.00		69,128.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA	2,001.00			
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	48,255.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	KCP&L GMO	2,890.00			
23	Empire District Electric	1,927.00			
24	Westar	5,855.00			
25					
26					
27					
28	Total	10,672.00			
29	Balance-End of Year	175,601.00		69,128.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	1,992.00		1,992.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	1,992.00			
40	Balance-End of Year			1,992.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)		39,588		
45	Gains				
46	Losses				

Name of Respondent Kansas City Power & Light Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of <u>2010/Q4</u>
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Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferrors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2012		2013		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
69,128.00		69,128.00		1,778,651.00		2,218,562.00		1
								2
								3
				69,128.00		69,128.00		4
						2,001.00		5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
						48,255.00		17
								18
								19
								20
								21
						2,890.00		22
						1,927.00		23
						5,855.00		24
								25
								26
								27
						10,672.00		28
69,128.00		69,128.00		1,847,779.00		2,230,764.00		29
								30
								31
								32
								33
								34
								35
1,992.00		1,992.00		51,792.00		59,760.00		36
				1,992.00		1,992.00		37
								38
						1,992.00		39
1,992.00		1,992.00		53,784.00		59,760.00		40
								41
								42
								43
							39,588	44
								45
								46

Name of Respondent Kansas City Power & Light Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Schedule Page: 228 Line No.: 18 Column: b

The allowances relinquished in 2010 include 1 allowance related to 2009.

Name of Respondent Kansas City Power & Light Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of <u>2010/Q4</u>
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Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year		2011	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	15,948.00		14,989.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	47.00			
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	MJMECU	35.00			
10	KEPCO	10.00			
11					
12					
13					
14					
15	Total	45.00			
16					
17	Relinquished During Year:				
18	Charges to Account 509	13,186.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	KCP&L GMO	472.00			
23	Empire District Electric	605.00			
24	MJMECU	15.00			
25	KEPCO	4.00			
26					
27					
28	Total	1,096.00			
29	Balance-End of Year	1,758.00		14,989.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent Kansas City Power & Light Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4
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Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferrors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2012		2013		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
14,989.00		14,989.00		14,989.00		75,904.00		1
								2
								3
						47.00		4
								5
								6
								7
								8
						35.00		9
						10.00		10
								11
								12
								13
								14
						45.00		15
								16
								17
						13,186.00		18
								19
								20
								21
						472.00		22
						605.00		23
						15.00		24
						4.00		25
								26
								27
						1,096.00		28
14,989.00		14,989.00		14,989.00		61,714.00		29
								30
								31
								32
								33
								34
								35
								36
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								39
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								46

Name of Respondent Kansas City Power & Light Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Schedule Page: 229 Line No.: 9 Column: b
Annual allowances

Schedule Page: 229 Line No.: 10 Column: b
Annual allowances

Schedule Page: 229 Line No.: 22 Column: b
Seasonal allowances 188
Annual allowances 284
Total 472

Schedule Page: 229 Line No.: 23 Column: b
Seasonal allowances 125
Annual allowances 480
Total 605

Schedule Page: 229 Line No.: 29 Column: l
Ending balance made up of
Seasonal allowances 19,467
Annual allowances 42,247
Total 61,714

Name of Respondent
 Kansas City Power & Light Company

This Report Is:
 (1) An Original
 (2) A Resubmission

Date of Report
 (Mo, Da, Yr)
 04/15/2011

Year/Period of Report
 End of 2010/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	None					
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

Name of Respondent
 Kansas City Power & Light Company

This Report Is:
 (1) An Original
 (2) A Resubmission

Date of Report
 (Mo, Da, Yr)
 04/15/2011

Year/Period of Report
 End of 2010/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
21	None					
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL					

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	Transmission Studies				
2	None				
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	Generation Studies				
22	None				
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Missouri Case No. EU-2004-0294 and					
2	Kansas Docket No. 04-WSEE-605-ACT:					
3	Non-nuclear asset retirement obligations recorded					
4	in accordance with ASC 410	23,785,772	3,684,458			27,470,230
5						
6						
7	Deferred Regulatory Asset-Recoverable Taxes:					
8	Gross up of tax related items to be recovered					
9	from future rate payers	201,426,288	20,852,214			222,278,502
10						
11						
12	Missouri Case Nos. ER-2006-0314, ER-2007-0291, and					
13	ER-2009-0089 and Kansas Docket Nos. 06-KCPE-828-RTS					
14	07-KCPE-905-RTS, 09-KCPE-246 RTS, 10-KCPE-415-RTS					
15	and 07-ATMG-387-ACT:					
16	Pension costs deferred for future recovery	408,537,691	35,613,953	926, 107	58,021,552	386,130,092
17						
18						
19	Missouri Case No. EO-2005-0329:					
20	Represents the deferred costs for the energy					
21	efficiency and affordability programs as provided					
22	in the Missouri Public Service Commission order.					
23	Each vintage year will be amortized over 10 years.	22,521,096	10,262,288	908	1,255,665	31,527,719
24						
25						
26	Kansas Docket No. 04-KCPE-1025-GIE and					
27	07-KCPE-905-RTS:					
28	Represents the deferred costs for the energy					
29	efficiency and affordability programs as provided					
30	in the Kansas Corporation Commission orders.					
31	These costs will be recovered through an Energy					
32	Efficiency Rider to be filed by March 31 of each					
33	year to recover costs incurred during the previous					
34	calendar year. Costs are to be amortized over 1					
35	year starting each July.	12,829,938	7,822,736	908	7,741,112	12,911,562
36						
37						
38	Kansas Docket No. 06-KCPE-828-RTS:					
39	Deferred costs associated with the 2006 rate case					
40	preparation and presentation to the Kansas					
41	Corporation Commission to be amortized over					
42	4 years beginning January 1, 2007.	304,330		928	304,330	
43						
44	TOTAL	722,643,301	120,789,783		72,313,476	771,119,608

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Kansas Docket No. 07-KCPE-905-RTS:					
2	Deferred costs associated with the 2007 rate case					
3	preparation and presentation to the Kansas					
4	Corporation Commission with remaining balance					
5	to be amortized over 4 years beginning					
6	December 1, 2010 per Docket No. 10-KCPE-415-RTS.	437,242		928	223,943	213,299
7						
8						
9	Missouri Case No. ER-2009-0089 and					
10	Kansas Docket No. 09-KCPE-246-RTS:					
11	Deferred costs associated with the 2008 rate case					
12	preparation and presentation to the Missouri					
13	Public Service Commission and Kansas Corporation					
14	Commission to be amortized over 2 years for					
15	Missouri beginning September 1, 2009 and					
16	remaining balance amortized over 4 years for					
17	Kansas beginning December 1, 2010 per Docket					
18	No. 10-KCPE-415-RTS.	2,944,885		928	1,139,564	1,805,321
19						
20						
21	Missouri Case No. ER-2010-0355 and					
22	Kansas Docket No. 10-KCPE-415-RTS:					
23	Deferred costs associated with the 2010 rate case					
24	preparation and presentation to the Missouri Public					
25	Service Commission and Kansas Corporation					
26	Commission to be amortized over 4 years in Kansas					
27	beginning December 1, 2010.	3,677,565	6,703,692	928	118,119	10,263,138
28						
29						
30	Kansas Docket No. 06-KCPE-828-RTS:					
31	Deferred costs associated with the Talent					
32	Assessment to be amortized over 10 years					
33	beginning January 1, 2007.	151,740		923	21,678	130,062
34						
35						
36	Missouri Case No. ER-2006-0314:					
37	Represents the Missouri jurisdictional non-labor					
38	expenses charged to the strategic initiative					
39	projects. These costs are being amortized over 5					
40	years beginning January 1, 2007.	799,664		923	399,832	399,832
41						
42						
43						
44	TOTAL	722,643,301	120,789,783		72,313,476	771,119,608

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Missouri Case No. ER-2007-0291:					
2	Missouri jurisdictional expenses incurred relating					
3	to the research and development tax credit					
4	studies. These costs will be amortized over					
5	5 years beginning September 1, 2009.	367,946		923	78,846	289,100
6						
7						
8	Kansas Docket No. 07-KCPE-905-RTS:					
9	Kansas jurisdictional Talent Assessment					
10	costs to be amortized over 10 years					
11	beginning January 1, 2008.	3,220,867		920	402,608	2,818,259
12						
13						
14	Kansas Docket No. 07-KCPE-905-RTS:					
15	Kansas jurisdictional Employment Augmentation					
16	Programs to be amortized over 10 years					
17	beginning January 1, 2008.	211,346		923	26,418	184,928
18						
19						
20	Missouri Case No. ER-2007-0291:					
21	Missouri jurisdictional Talent Assessment					
22	costs to be amortized over 5 years					
23	beginning January 1, 2008.	2,904,310		920	968,103	1,936,207
24						
25						
26	Kansas Docket No. 07-KCPE-905-RTS:					
27	Energy Cost Adjustment	673,961	7,751,035			8,424,996
28						
29						
30	Kansas Docket No. 07-BHCG-1063-ACQ:					
31	Kansas jurisdictional transition costs for Great					
32	Plains Energy's acquisition of Aquila, to be					
33	amortized over 5 years beginning December 1, 2010					
34	per Kansas Docket No. 10-KCPE-415-RTS.	10,000,000		920, 923	166,667	9,833,333
35						
36						
37	Missouri Case No. EM-2007-0374:					
38	Missouri jurisdictional transition costs for Great					
39	Plains Energy's acquisition of Aquila.	19,251,486	230,255			19,481,741
40						
41						
42						
43						
44	TOTAL	722,643,301	120,789,783		72,313,476	771,119,608

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Kansas Docket No. 09-KCPE-246-RTS					
2	& 10-KCPE-415-RTS:					
3	Kansas jurisdictional difference between allowed					
4	rate base and financial costs booked for Iatan I					
5	and Iatan Common. Vintage 1 will be amortized					
6	over 47 years beginning December 1, 2010.	706,884	2,779,997	405	5,063	3,481,818
7						
8						
9	Missouri Case No. ER-2009-0089:					
10	Missouri jurisdictional difference between allowed					
11	rate base and financial costs booked for Iatan I					
12	and Iatan Common.	3,941,185	7,659,759			11,600,944
13						
14						
15	Missouri Case No. ER-2009-0089:					
16	Defer refueling costs at Wolf Creek Nuclear					
17	Operating Corporation to be amortized over 5 years					
18	beginning September 1, 2009.	1,465,876		524, 530	314,117	1,151,759
19						
20						
21	Missouri Case No. ER-2009-0089:					
22	Missouri jurisdictional deferred 2007 DSM					
23	advertising costs to be amortized over 10 years					
24	beginning September 1, 2009.	270,203		909	27,952	242,251
25						
26						
27	Missouri Case No. ER-2009-0089:					
28	Deferred 50% cost of the Economic Relief Pilot					
29	Program until the next general rate case, with					
30	cost recovery determined at that time.	17,210	233,104			250,314
31						
32						
33	Missouri Case No. EO-2005-0329:					
34	Deferred costs associated with the Iatan 2 project,					
35	Construction Accounting until the effective date					
36	of approved rates.		17,196,292			17,196,292
37						
38						
39	Other / Minor Regulatory Asset Items	2,195,816		524, 921	1,097,907	1,097,909
40						
41						
42						
43						
44	TOTAL	722,643,301	120,789,783		72,313,476	771,119,608

MISCELLANEOUS DEFERRED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than \$100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	Billing Work Orders	18,753,889	4,284,569	Various	20,559,814	2,478,644
2	Pension ASC 715 Partner Share		2,027,043	Various	4,336,759	-2,309,716
3	OPEB ASC 715	1,817,077	547,213	Various	738,196	1,626,094
4	OPEB ASC 715 - Partners' Share	-223,928	369,475	Various	343,387	-197,840
5						
6	GMO portion of Iatan Retention	19,744,864	5,146,561	Various	21,239,461	3,651,964
7						
8	Misc. Work Orders, Other	24,351	2,850,519	Various	2,856,034	18,836
9						
10	Miscellaneous, Other	200	357,326	Various	7,847	349,679
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
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24						
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36						
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39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress	16,894				10,161
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	40,133,347				5,627,822

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	Accumulated Deferred Income Taxes - Federal	412,358,130	438,445,950
3	Accumulated Deferred Income Taxes - State	56,595,973	60,566,321
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	468,954,103	499,012,271
9	Gas		
10	Accumulated Deferred Income Taxes - Federal		
11	Accumulated Deferred income Taxes - State		
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)		
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	468,954,103	499,012,271

Notes

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report 2010/Q4
Kansas City Power & Light Company			
FOOTNOTE DATA			

Schedule Page: 234 Line No.: 18 Column: c

This footnote provides additional details for use in the FERC transmission formula rate, Docket No. ER10-230-000.

		<u>2010</u>
<u>Accumulated Deferred Income Tax Utility Oper Other</u>		<u>YE Balance</u>
190200	Emission credit sales	33,425,065
	Bond refunding amortization	0
	Retail Regulatory Assets/Liabilities	3,715,852
	KS & MO Additional Credit Amort	79,344,742
	Prior Years Depr Adj (Combustion Turbine)	3,381,651
	Bonus Pay Accrual	264,666
	FAS 106 Postretirement Benefits	12,546,582
	Customer Advances (Retail)	721,871
	Tax gross up on CIACs	3,243,654
	Partnership entries	2,976
	Tax Interest (FIN 48 & other contingencies)	543,656
	Wolf Creek Decomm Co	256,362
	AFDC Debt not in service	0
	Tax Interest Capitalized in CWIP	3,264,037
	Deferred Compensation - Non-current	6,996,500
	MTM - Interest Rate Lock	0
	FIN 48 Adjustments	882,327
	Stock Compensation Accrual	2,083,364
	Interest Rate Lock - through P&L	11,238,987
	Vacation Accrual	7,745,898
	Life insurance paid - severed Aquila employees	0
	Bad Debt	0
	Injuries and Damages	1,170,232
	Deferred Compensation - (Current)	260,377
	Interest Rate Lock - OCI Interest	23,168,826
	<u>Reclass from 282 for Debit balances</u>	
	Cost of Removal (normalized)	16,199,772
	AFUDC other than nuclear fuel	752,513
	Capitalized computer hardware	2,169,938
	Capitalized tax interest	46,962,262
	CIAC	24,117,535
	FAS106/Pensions	0
	KEPCO interest refund	198,430
	Repair retirements reversed	1,676,350
	Vehicle tax depreciation capitalized	8,664,648
	Other	88,148
	Transmission CIAC	0
	Deferred Liability -Lease 1 KC Place	9,314,191
	Miscellaneous Accruals	0
	SO2 Allowance Write-down	529,149
190400	Deferred Taxes - OCI (Gas Hedge)	6,879
190500	GBC Tax Credit Carry forward (Generation)	101,538,292
190601	FASB 109 Adjustment	91,011,058
190602	FASB 109 MO R&D Credit Deferred	453,138
190603	FASB 109 Medicare Subsidies	0
190300	Federal NOL	1,003,191
190301	State NOL	69,152
	Total	499,012,271

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
 2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	A/C 201 - Common Stock - No Par	1,000		
2				
3				
4	TOTAL COMMON	1,000		
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Name of Respondent
Kansas City Power & Light Company

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
04/15/2011

Year/Period of Report
End of 2010/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
 4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
 5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
- Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
Shares (e)	Amount (f)	AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
		Shares (g)	Cost (h)	Shares (i)	Amount (j)	
1	487,041,247					1
						2
						3
1	487,041,247					4
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OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.

- (a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
- (b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
- (c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
- (d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	A/C 208 - Donations received from Stockholders	
2		
3	A/C 209 - Reduction in Par of Stated Value of Capital Stock	
4		
5	A/C 210 - Gain on Resale or Cancellation of Reacquired Capital Stock	
6		
7	A/C 211 - Miscellaneous Paid-In Capital, December 31, 2009	1,076,114,704
8	Equity Investment in KCP&L by Great Plains Energy, Inc.	
9	Subtotal Balance - December 31, 2010	1,076,114,704
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40	TOTAL	1,076,114,704

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
 2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	None	
2		
3		
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21		
22	TOTAL	

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Pledged in Support of Pollution Control Bonds:		
2	Variable Rate 1992 Series Due 2017	31,000,000	1,421,702
3	Variable Rate 1993 Series Due 2012	12,366,000	288,784
4	Variable Rate 1993 Series A Due 2023	40,000,000	957,310
5	Variable Rate 1993 Series B Due 2023	39,480,000	943,421
6	Variable Rate 1994 Series Due 2015	13,982,500	427,145
7	Variable Rate 2005 Series Due 2035	21,940,000	560,697
8	SUBTOTAL	158,768,500	4,599,059
9	Mortgage Bonds 7.15%	400,000,000	4,032,839
10	Mortgage Bonds 7.15% Discount		432,000 D
11	SUBTOTAL	400,000,000	4,464,839
12	Unsecured Notes:		
13	Senior Notes 6.50%	150,000,000	1,058,971
14	Senior Notes 6.50% Discount		223,500 D
15	Senior Notes 6.05%	250,000,000	2,259,054
16	Senior Notes 6.05% Discount		1,505,000 D
17	Senior Notes 5.85%	250,000,000	1,843,406
18	Senior Notes 5.85% Discount		420,000 D
19	Senior Notes 6.375%	350,000,000	2,566,730
20	Environmental Improvement Revenue Refunding Bonds:		
21	Variable Rate Series A Due 2035	73,250,000	961,789
22	Variable Rate Series B Due 2035	73,250,000	961,789
23	4.65% Fixed Rate Series C Due 2035	50,000,000	1,337,086
24	Variable Rate Series A-2 Due 2035	10,000,000	95,429
25	Missouri Tax-Exempt Series 2008 Due 2038	23,400,000	408,088
26	SUBTOTAL	1,229,900,000	13,640,842
27	Other Long-Term Debt (Account 224):		
28	MODOT Highway Bridge	3,491,904	
29	SUBTOTAL	3,491,904	
30			
31			
32			
33	TOTAL	1,792,160,404	22,704,740

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

- 10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
- 11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
- 12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
- 13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
- 14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
- 15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
- 16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
						1
091592	070117	091592	070117	31,000,000	1,627,499	2
101493	010212	101493	010212	12,366,000	494,640	3
120793	120123	120793	120123	40,000,000	2,100,000	4
120793	120123	120793	120123	39,480,000	1,974,000	5
022394	030115	030194	022815	13,982,000	566,271	6
090105	090135	090105	090135	21,940,000	1,020,210	7
				158,768,000	7,782,620	8
040109	040119	040109	040119	400,000,000	33,942,000	9
						10
				400,000,000	33,942,000	11
						12
111501	111511	111501	111511	150,000,000	9,750,000	13
						14
111705	111535	111705	111535	250,000,000	14,726,664	15
						16
060407	061517	060407	061517	250,000,000	14,293,502	17
						18
030108	030118	030108	030118	350,000,000	26,432,073	19
						20
091907	090135	091907	090135	63,250,000	3,241,562	21
091907	090135	091907	090135	73,250,000	3,937,188	22
090105	090135	090105	090135	50,000,000	2,325,000	23
030108	090135	030108	090135	10,000,000	321,875	24
050108	050138	050108	050138	23,400,000	1,146,600	25
				1,219,900,000	76,174,464	26
						27
052709	090118			3,271,797		28
				3,271,797		29
						30
						31
						32
				1,781,939,797	117,899,084	33

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report 2010/Q4
Kansas City Power & Light Company			
FOOTNOTE DATA			

Schedule Page: 256 Line No.: 28 Column: i

The MODOT Highway Bridge note payable is a direct financing agreement with Missouri Transportation Finance Company. The interest expense incurred during the construction period will be considered part of the bridge capital expenditure. Interest incurred after construction is completed will be charged as an operating expense. Thus, no interest expense was recognized in 2010 on this note payable.

Schedule Page: 256 Line No.: 32 Column: i

Great Plains Energy
FERC Form 1 Footnote
December 31, 2010

The FERC transmission formula rate uses Great Plains Energy's Long-Term Debt interest, Preferred Dividends and Capital Structure component, per Docket No. ER10-230-000. This additional information has been disclosed in the footnote below.

Long-Term Debt Interest

Date	Interest on Long Term Debt	Amort of Debt Disc and Exp	Amort of Loss on Reacquired Debt	Amort of Premium on Debt-Credit	Amort of Gain on Reacquired Debt-Credit
01/31/10	20,878,370	387,432	36,647	0	0
02/28/10	20,868,562	387,432	36,647	0	0
03/31/10	20,862,827	387,432	36,647	0	0
04/30/10	20,837,716	392,099	36,647	0	0
05/31/10	20,842,912	387,664	36,647	0	0
06/30/10	20,830,651	387,703	36,647	0	0
07/31/10	20,825,642	387,707	36,647	0	0
08/31/10	21,361,782	810,024	36,647	0	0
09/30/10	21,489,837	634,199	54,817	0	0
10/31/10	21,609,705	644,222	54,817	0	0
11/30/10	21,594,527	641,768	54,818	0	0
12/31/10	21,531,609	642,066	54,818	0	0
Total	253,534,140	6,089,748	512,446	0	0

Preferred Dividends

Date	Balance
01/31/10	137,167
02/28/10	137,166
03/31/10	137,167
04/30/10	137,167
05/31/10	137,166
06/30/10	137,167
07/31/10	137,167
08/31/10	137,166
09/30/10	137,167
10/31/10	137,167
11/30/10	137,166
12/31/10	137,167
Total	1,646,000

Capital Structure Components

Date	Adjusted Long Term Debt Balance of Consolidated GPE	Current Maturities LTD Balance of Consolidated GPE	Preferred Stock	Proprietary Capital	Treasury Stock	OCI Account 219	Noncontrolling interest
12/31/09	3,128,426,193	1,345,106	39,000,000	2,832,720,025	(5,493,261)	(44,871,932)	1,165,599
01/31/10	3,128,443,626	1,345,106	39,000,000	2,860,754,465	(5,701,211)	(44,604,428)	1,165,599
02/28/10	3,127,336,058	1,345,106	39,000,000	2,840,022,272	(7,134,614)	(44,099,053)	1,165,599
03/31/10	2,990,043,490	138,655,106	39,000,000	2,837,202,074	(7,134,614)	(48,191,685)	1,165,599

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kansas City Power & Light Company		04/15/2011	2010/Q4

FOOTNOTE DATA

04/30/10	2,990,060,922	138,655,106	39,000,000	2,839,538,262	(7,134,614)	(47,649,997)	1,174,971
05/31/10	2,990,078,355	138,655,106	39,000,000	2,829,077,329	(8,052,389)	(47,399,385)	1,174,971
06/30/10	2,793,095,788	335,655,106	39,000,000	2,876,755,317	(8,333,025)	(55,457,584)	1,174,971
07/31/10	2,793,113,220	335,655,106	39,000,000	2,936,180,183	(8,580,663)	(54,942,200)	1,188,095
08/31/10	3,043,018,846	335,655,106	39,000,000	2,964,904,232	(8,607,681)	(55,194,138)	1,188,095
09/30/10	3,042,700,179	335,774,294	39,000,000	2,982,480,651	(8,607,681)	(59,770,497)	1,188,095
10/31/10	3,042,720,806	335,774,294	39,000,000	2,955,682,820	(8,858,635)	(59,170,483)	1,250,843
11/30/10	3,042,741,433	335,774,294	39,000,000	2,958,478,995	(8,858,635)	(58,567,427)	1,200,843
12/31/10	2,892,762,060	485,774,294	39,000,000	2,950,917,508	(8,858,635)	(56,119,251)	1,214,213
13 Month Ave	3,000,349,306	224,620,241	39,000,000	2,897,285,703	(7,796,589)	(52,002,928)	1,185,961

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.

2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be filed, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.

3. A substitute page, designed to meet a particular need of a company, may be used as long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	163,228,391
2		
3		
4	Taxable Income Not Reported on Books	
5	Contributions in Aid of Construction	5,900,000
6	Emission Allowances Sold	-293,556
7	Deferred Liability - Lease 1 KC Place	2,220,079
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Income Tax Provision	79,524,753
11	Employee Pensions	9,481,415
12	Equity in Subsidiaries	-3,331,378
13	Other	21,629,803
14	Income Recorded on Books Not Included in Return	
15	AFDC	-44,236,263
16	Company Owned Life Insurance	-2,183,042
17	Iatan II - Deferred Revenue & Fuel Costs	-17,196,292
18		
19	Deductions on Return Not Charged Against Book Income	
20	State Income Tax	-4,614,398
21	Excess of Straight-Line over Liberalized Depreciation	-81,981,162
22	Repair Allowance	-7,000,000
23	Repair Expenditures	-25,330,918
24	Refueling Outage Costs	10,125,952
25	Other	-33,004,882
26		
27	Federal Tax Net Income	72,938,502
28	Show Computation of Tax:	
29		
30	Federal Tax \$72,938,502 @ 0.35	25,528,476
31		
32	Prior Tax Return Adjustments	-23,613,499
33	Deferral of Prior Year Tax Credits	-158,022
34	Net Operating Loss	374,607
35	Other Adjustments	25,203
36		
37		
38	Federal Income Tax (acct # 409.1 & 409.2)	2,156,765
39		
40	NOTE: Positive numbers are additions to income	
41	and negative numbers are deductions from income.	
42		
43		
44		

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Kansas City Power & Light Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 04/15/2011	2010/Q4
FOOTNOTE DATA			

Schedule Page: 261 Line No.: 13 Column: b

Limited Vacation Accrual	\$ 1,546,437
FASB 106 (ASC 715)	(1,780,342)
Injury Damage Reserve	688,871
Stock Compensation	(2,966,040)
Loss on Reacquired Debt-Amortization	301,969
Deferred Compensation	2,341,824
Clearing Accounts	(1,594,467)
Excess MO Gross Margin	3,343,107
162(m) Limitation	2,126,649
Iatan 1 & 2 Book Write-Downs	11,963,614
KS Legal Fees Reimbursement	685,704
KS 1 KC Place Rent Refunded to Ratepayers	948,459
Impairment of SO2 Allowances Held for Investment	1,360,280
Computers Expensed for Book	750,000
Other	1,913,738
Total	<u>\$21,629,803</u>

Schedule Page: 261 Line No.: 25 Column: b

Dividend Paid on ESOP	\$ (2,600,000)
Deferred Transition Costs	(63,589)
KS Regulatory Energy Cost Adjustment	(8,770,094)
Tax Interest	204,622
Talent Assessment	1,418,807
Deferred STB Expense	(418,338)
Jurisdiction Difference Iatan 1 and Common	(10,434,693)
Economic Relief Pilot Program	(233,104)
Advertising Costs	27,952
Rate Case Expense	(4,917,737)
Customer Demand Programs	(9,088,247)
Other	1,869,539
Total	<u>\$(33,004,882)</u>

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b) amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	PAYROLL					
2	Federal Unempl. Ins.	92,096		188,158	188,257	
3	FICA	2,218,353		21,703,794	21,727,726	
4	Payroll Taxes - WCNO	139,650		3,186,578	3,141,309	
5	Unemployment - Missouri	94,363		429,046	428,072	
6	Unemployment - Kansas			34,602	24,762	
7	Unemployment - Washington	176		265	261	
8	Unemployment - Iowa	10		128	132	
9	Unemployment - Oregon	134		-134		
10						
11	K.C. Earnings - Mo.	257,730		87,928	270,000	
12						
13	Gross Receipts - Mo.	961,746	552,882	54,127,094	54,245,145	
14						
15	FRANCHISE					
16	Missouri	-555,648		697,613	141,966	
17	Kansas					
18						
19	BUSINESS LICENSE					
20	Occupational - Mo.			-14,982	-14,982	
21	Occupational - Ks.					
22						
23	PROPERTY					
24	Missouri - 2010			36,750,708	36,750,708	
25	Kansas - 2010			35,350,824	17,853,962	
26	Kansas - 2009	17,074,266			17,074,266	
27	Special Assessments -					
28	Special Assessments -	50,567			9,194	
29	Rail Car - Arkansas					
30	Rail car - Colorado			161	161	
31	Rail Car - Nebraska	150,388		116,794	150,388	
32	Rail Car - Oklahoma					
33	Rail Car - Arizona					
34	Rail Car - Indiana					
35	Rail Car - Montana			26	26	
36	Rail Car - Wyoming			26,941	26,941	
37	Rail Car - Kansas	12,900		25,688	25,744	
38	Rail Car - Missouri			40,177	40,177	
39						
40	SUBTOTAL	20,496,731	552,882	152,751,409	152,084,215	
41	TOTAL	22,380,642	552,882	155,487,887	152,096,398	-4,608,206

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b) amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	FEDERAL	1,505,570		2,156,765		-3,662,335
2						
3	STATE					
4	Missouri	272,382		410,804		-684,665
5	Kansas	105,959		156,726		-261,206
6						
7	OTHER					
8	Iowa			12,000	12,000	
9	Pennsylvania			183	183	
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	22,380,642	552,882	155,487,887	152,096,398	-4,608,206

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

- 5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
- 6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
- 7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
- 8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
- 9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
91,997		32,976			155,182	2
2,194,421		8,375,172			13,328,622	3
184,919		2,851,936			334,642	4
95,337		428,073			973	5
9,840		24,762			9,840	6
180					265	7
6		128				8
		-134				9
						10
75,658		85,349			2,579	11
						12
969,976	679,164	54,127,094				13
						14
						15
		697,953			-340	16
						17
						18
						19
		-14,982				20
						21
						22
						23
		28,088,855			8,661,853	24
17,496,862		34,581,847			768,977	25
						26
						27
41,373						28
						29
					161	30
116,794					116,794	31
						32
						33
						34
					26	35
					26,941	36
12,844					25,688	37
					40,177	38
						39
21,290,207	679,164	129,279,029			23,472,380	40
21,290,207	679,164	139,354,288			16,133,599	41

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

- 5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
- 6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
- 7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
- 8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
- 9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
		8,324,281			-6,167,516	1
						2
						3
-1,479		1,258,619			-847,815	4
1,479		480,176			-323,450	5
						6
						7
		12,000				8
		183				9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
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						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
21,290,207	679,164	139,354,288			16,133,599	41

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report 2010/Q4
Kansas City Power & Light Company			
FOOTNOTE DATA			

Schedule Page: 262.1 Line No.: 1 Column: f

Payments to holding company pursuant to tax sharing agreement	\$(13,238,789)
Reclass to /from income tax receivables	7,965,409
FIN 48 adjustments (ASC 740)	1,592,506
Miscellaneous adjustments	18,539
Total	<u>\$ (3,662,335)</u>

Schedule Page: 262.1 Line No.: 4 Column: f

Payments to holding company pursuant to tax sharing agreement	\$ (1,626,972)
Reclass to/from income tax receivables	830,579
FIN 48 adjustments (ASC 740)	150,314
Miscellaneous adjustments	(38,586)
Total	<u>\$ (684,665)</u>

Schedule Page: 262.1 Line No.: 5 Column: f

Payments to holding company pursuant to tax sharing agreement	\$ (620,705)
Reclass to/from income tax receivables	316,874
FIN 48 adjustments (ASC 740)	57,346
Miscellaneous adjustments	(14,721)
Total	<u>\$ (261,206)</u>

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g). Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%	23,380,523			411.4	1,386,435	
6	15%	111,474,621	411.4	-4,187,121	411.4	715,250	
7							
8	TOTAL	134,855,144		-4,187,121		2,101,685	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11	Non-utility	825,694			420	30,844	
12							
13	A/C 255	135,680,838		-4,187,121		2,132,529	
14							
15							
16							
17							
18							
19							
20							
21							
22							
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47							
48							

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
21,994,088	47 years		5
106,572,250	50 years		6
			7
128,566,338			8
			9
			10
794,850	33 years		11
			12
129,361,188			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
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			44
			45
			46
			47
			48

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report 2010/Q4
Kansas City Power & Light Company			
FOOTNOTE DATA			

Schedule Page: 266 Line No.: 6 Column: d

True-up of 2009 Advanced coal credit \$(4,187,121)

Schedule Page: 266 Line No.: 6 Column: i

The 50 year average period of allocation to income for the advanced coal credit may be subsequently adjusted from the result of pending rate cases.

Schedule Page: 266 Line No.: 13 Column: h

This footnote provides additional details for use in the FERC transmission formula rate, Docket No. ER10-230-000.

<u>Accumulated Deferred Investment Tax Credits</u>		<u>2010</u> <u>YE Balance</u>
255520	ITC - Wolf Creek ITC	19,492,106
255634	ITC - Electric	2,501,982
255600	ITC - Wolf Creek Sales	794,850
255700	ITC - Iatan 2 Advanced Coal Credit	<u>106,572,250</u>
	Total	<u>129,361,188</u>

OTHER DEFERRED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than \$100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Wolf Creek					
2	Deferred Compensation & Inter	7,231,447	Various	1,000,851	1,460,294	7,690,890
3						
4	Tax Gross-Up Contributions in					
5	Aid of Construction	8,588,268	Various	773,699	523,874	8,338,443
6						
7	Long Term Compensation	9,242,215	431	1,765,148	3,108,558	10,585,625
8						
9	ASC 740 (FIN 48) Tax - State	434,547	Various	434,547	306,592	306,592
10						
11	Lease	23,751,137	931	2,356,733	2,549,533	23,943,937
12						
13	Other	1,931,595	186	4,888,809	3,026,088	68,874
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
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36						
37						
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39						
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41						
42						
43						
44						
45						
46						
47	TOTAL	51,179,209		11,219,787	10,974,939	50,934,361

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amortizable property.
2. For other (Specify), include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities			
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)			
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)			
18	Classification of TOTAL			
19	Federal Income Tax			
20	State Income Tax			
21	Local Income Tax			

NOTES

Name of Respondent
 Kansas City Power & Light Company

This Report Is:
 (1) An Original
 (2) A Resubmission

Date of Report
 (Mo, Da, Yr)
 04/15/2011

Year/Period of Report
 End of 2010/Q4

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
							2
							3
							4
							5
							6
							7
							8
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							21

NOTES (Continued)

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify), include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	702,221,121	111,662,049	
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	702,221,121	111,662,049	
6	Reclass per FA96-19-000	68,756,102		
7	FASB109 (ASC 740)	136,135,105		
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	907,112,328	111,662,049	
10	Classification of TOTAL			
11	Federal Income Tax	768,363,784	94,582,635	
12	State Income Tax	138,748,544	17,079,414	
13	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
	4,653,846					809,229,324	2
							3
							4
	4,653,846					809,229,324	5
					32,073,494	100,829,596	6
		182	14,867,234	254	954,956	122,222,827	7
							8
	4,653,846		14,867,234		33,028,450	1,032,281,747	9
							10
	3,942,011		12,593,197		27,976,542	874,387,753	11
	711,835		2,274,037		5,051,908	157,893,994	12
							13

NOTES (Continued)

Name of Respondent Kansas City Power & Light Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Schedule Page: 274 Line No.: 6 Column: j

Reclass to/from account 190 per FA96-19-000.

Schedule Page: 274 Line No.: 7 Column: h

The amount of \$14,867,234 reflects the change in deferred income tax liability balance for the FAS109 (ASC 740) adjustment related to AFUDC equity and basis difference previously flowed through.

Schedule Page: 274 Line No.: 7 Column: j

The amount of \$954,956 reflects the change in deferred income tax liability balance for the FAS109 (ASC 740) adjustment related to excess taxes.

Schedule Page: 274 Line No.: 9 Column: k

This footnote provides additional details for use in the FERC transmission formula rate, Docket No. ER10-230-000.

Accumulated Deferred Income Tax Other Property		<u>2010</u> YE Balance
282611	Total Plant	809,229,324
282611	Reclass Debit Balances to 190	100,829,596
282601	FASB 109 Adjustment	122,222,827
	Total	<u>1,032,281,747</u>

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify), include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3		138,725,114	-23,710,353	-5,607,202
4				
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	138,725,114	-23,710,353	-5,607,202
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18				
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	138,725,114	-23,710,353	-5,607,202
20	Classification of TOTAL			
21	Federal Income Tax	118,342,080	-20,072,589	-4,749,545
22	State Income Tax	20,383,034	-3,637,764	-857,657
23	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
							2
					48,642,456	169,264,419	3
							4
							5
							6
							7
							8
					48,642,456	169,264,419	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
					48,642,456	169,264,419	19
							20
					41,015,100	144,034,136	21
					7,627,356	25,230,283	22
							23

NOTES (Continued)

Name of Respondent Kansas City Power & Light Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Schedule Page: 276 Line No.: 3 Column: j

Other Adjustments:

Reclass to/from account 190 per FA96-19-000	10,077,222
Change in Deferred Tax Liability per FAS 109 Adjustment (ASC 740)	35,719,448
Other comprehensive income - Interest Rate Hedge	3,396,645
Inter-Unit transfers	1,121,352
FIN 48 Adjustments (ASC 740)	(1,672,211)
	48,642,456

Schedule Page: 276 Line No.: 19 Column: d

Reconciliation to the income statement (page 114, line 18):

Page 234, Account 190	1,126,221	
Page 276, Account 283	(5,607,202)	
SUBTOTAL	(4,480,981)	
Page 272, Account 254	194,111	R&D Credit Claims in accordance with MO Case No. ER-2007-0291
TOTAL	(4,286,870)	

Schedule Page: 276 Line No.: 19 Column: k

This footnote provides additional details for use in the FERC transmission formula rate, Docket No. ER10-230-000.

Accumulated Deferred Income Tax Other Utility

283300	<u>Deferred Tax Miscellaneous:</u>	<u>2010 YE Balance</u>
	Miscellaneous Accruals	0
	Bond Refinancing (Loss on Reacq Debt)	1,956,293
	Clearing Accounts	3,995,206
	Retail Regulatory Assets/Liabilities	46,433,255
	Employee pensions	10,574,621
	Prepaid Gross Receipts Tax	264,195
	Coal Premium Offset	0
	Interest on Decommissioning & Decontamination	249,856
	Section 174 Ded in CWIP (Iatan-Production)	0
	AFUDC Debt in CWIP	1,128,893
	Book Amort Mortgage Register Taxes	1,048
	Software Deduction in CWIP	7,607,859
	Nonutility Depreciation	0
	Nonutility Capitalized Interest	0
	Nonutility Book Capitalized Software	0
	Jurisdictional Diff Iatan 1 and Common	5,867,194
	Stock Compensation Accrual	0
	SmartGrid Dem Grant Deferred	139,000
283100	Nuclear Fuel	4,198,120
283601	FASB 109 Adjustment	86,466,339
283410/510	FIN 48 Liability (after FERC Reclass)	382,540
283400	Deferred Taxes - OCI (Gas Hedge)	0
	Total	169,264,419

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	Emissions Allowances Transactions					
2	per Missouri Order EO-2008-0329 and					
3	Kansas Order 04-KCPE-1025-GIE, with					
4	Kansas emission allowances to be amortized					
5	over 22 years beginning December 1, 2010.	86,219,173	501,509	293,555		85,925,618
6						
7	Deferred Regulatory Liability-ASC 740	123,833,415		18,779,881		105,053,534
8						
9	Asset Retirement Obligation related					
10	to the decommissioning trust per					
11	FERC Order 631, MO Case No.					
12	EU-2004-0294 and KS Docket No.					
13	04-WSEE-605-ACT.	33,439,494	230,456,524		11,441,321	44,880,815
14						
15	DOE Refund of Enrichment Overcharges					
16	per KS Docket No. 04-KCPE-905-ACT,					
17	to be amortized over 3 years beginning					
18	January 2008.	60,435	518	60,435		
19						
20	R&D Credit Claims in accordance with					
21	MO Case No. ER-2007-0291, to be amortized					
22	over 5 years beginning September 2009.	905,850	411	194,111		711,739
23						
24	Excess MO Wholesale Gross Margin					
25	in accordance with MO Case No.					
26	ER-2007-0291 to be amortized over					
27	10 years beginning September 2009.	3,508,466	440,442,444	408,974	3,752,080	6,851,572
28						
29	Excess STB Settlement in accordance					
30	with MO Case No. ER-2006-0314 and					
31	KS Docket No. 06-KCPE-828-RTS, to be					
32	amortized over 10 years in MO beginning September					
33	2009 and over 2 years in KS beginning August					
34	2009.	1,484,924	501	418,338		1,066,586
35						
36	Energy Cost Adjustment per					
37	KS Docket No. 07-KCPE-905-RTS	1,269,519		1,019,059		250,460
38						
39	Kansas Legal Fee Reimbursement per					
40	Kansas Docket No. 10-KCPE-415-RTS, to					
1	be amortized over 3 years beginning					
2	December 1, 2010.		923	19,592	705,296	685,704
3						
4	One KC Place Lease Abatement per					
41	TOTAL	250,721,276		21,214,125	16,867,336	246,374,487

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
5	Kansas Docket No. 10-KCPE-415-RTS,					
6	to be amortized over 4 years beginning					
7	December 1, 2010.		931	20,180	968,639	948,459
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41	TOTAL	250,721,276		21,214,125	16,867,336	246,374,487

Name of Respondent Kansas City Power & Light Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Schedule Page: 278 Line No.: 7 Column: a

Excess taxes due to change in tax rates	\$23.8 million
Investment tax credits	\$15.4 million
Medicare Subsidies	\$13.1 million
R&D Credits	\$ 0.6 million
Advance Coal Credit	\$70.9 million
Total	\$123.8 million

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of \$250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	568,510,559	471,833,300
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	608,463,743	542,311,742
5	Large (or Ind.) (See Instr. 4)	123,233,440	108,765,868
6	(444) Public Street and Highway Lighting	11,844,191	10,879,271
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,312,051,933	1,133,790,181
11	(447) Sales for Resale	188,875,535	166,181,993
12	TOTAL Sales of Electricity	1,500,927,468	1,299,972,174
13	(Less) (449.1) Provision for Rate Refunds	3,727,877	-61,863
14	TOTAL Revenues Net of Prov. for Refunds	1,497,199,591	1,300,034,037
15	Other Operating Revenues		
16	(450) Forfeited Discounts	3,031,212	2,796,932
17	(451) Miscellaneous Service Revenues	880,025	868,747
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	2,913,591	2,806,473
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	740,487	690,107
22	(456.1) Revenues from Transmission of Electricity of Others	12,350,369	10,192,837
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	19,915,684	17,355,096
27	TOTAL Electric Operating Revenues	1,517,115,275	1,317,389,133

ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
5,718,844	5,202,904	451,466	450,359	2
				3
7,705,500	7,506,464	57,934	57,725	4
1,955,516	1,884,401	2,068	2,097	5
87,133	86,921	113	115	6
				7
				8
				9
15,466,993	14,680,690	511,581	510,296	10
6,050,947	5,381,472	43	39	11
21,517,940	20,062,162	511,624	510,335	12
				13
21,517,940	20,062,162	511,624	510,335	14

Line 12, column (b) includes \$ 3,601,149 of unbilled revenues.
 Line 12, column (d) includes 24,214 MWH relating to unbilled revenues

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Kansas City Power & Light Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 04/15/2011	2010/Q4
FOOTNOTE DATA			

Schedule Page: 300 Line No.: 17 Column: b

Line 17 (451) Miscellaneous Service Revenues:

- \$498,245 Reconnect Charges
- \$288,960 Temporary Install Profit
- \$ 42,135 Replace Damaged Meter Charges
- \$ 25,567 Disconnect Service Charges
- \$ 20,230 OK on Arrival Fees
- \$ 4,865 Collection Services
- \$ 23 Miscellaneous
- \$880,025 Total

Schedule Page: 300 Line No.: 17 Column: c

Line 17 (451) Miscellaneous Service Revenues:

- \$532,670 Reconnect Charges
- \$232,732 Temporary Install Profit
- \$ 36,215 Replace Damaged Meter Charges
- \$ 32,585 OK on Arrival Fees
- \$ 26,854 Disconnect Service Charges
- \$ 7,691 Collection Services
- \$868,747 Total

Schedule Page: 300 Line No.: 21 Column: b

Line 21 (456) Other Electric Revenues:

- \$387,717 Use and Sales Tax Timely Filing Discount
- \$352,770 Non-Sufficient Funds Fee
- \$740,487 Total

Schedule Page: 300 Line No.: 21 Column: c

Line 21 (456) Other Electric Revenues:

- \$344,989 Use and Sales Tax
- \$333,010 Return Check Service Charges
- \$ 12,108 Facility Charges
- \$690,107 Total

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	None				
2					
3					
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40					
41					
42					
43					
44					
45					
46	TOTAL				

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	1ALDA-Area Lighting	1,016	304,330	1,064	955	0.2995
2	1RFEB-Residential Apts All Elec	1,605	138,085	14	114,643	0.0860
3	1RH1A-Residential Space Heat	500	53,298	157	3,185	0.1066
4	1RS1A-Residential Standard	2,021,698	214,053,744	191,173	10,575	0.1059
5	1RS1B-Residential Standard	1,005	119,730	40	25,125	0.1191
6	1RS2A-Residential Submeter	17,758	1,521,708	1,190	14,923	0.0857
7	1RS3A-Residential Sep Ht Meter	146,579	12,349,935	9,547	15,353	0.0843
8	1RS6A-Residential Elec Heat	537,126	46,779,221	38,372	13,998	0.0871
9	1RSDA-Residential Standard 3PH	1,927	178,440	76	25,355	0.0926
10	1RW1A-Residential Water Heat		374			
11	1RW2A-Res Water/Space Heat		640			
12	1RW3A-Res Water/Space Heat		2,086			
13	1RW6A-Res Water/Space Heat		739			
14	1RW7A-Res Water/Space Heat	697	54,196	26	26,808	0.0778
15	1TE1A-Residential Time of Day	655	65,730	42	15,595	0.1004
16	Excess Gross Margin		128,440			
17	Unbilled Revenue	4,500	314,827			0.0700
18	Total MO Residential	2,735,066	276,065,523	241,701	11,316	0.1009
19						
20						
21						
22	2ALDA-Area Lighting	1,175	340,793	2,013	584	0.2900
23	2RS1A-Residential Standard	1,947,052	204,425,539	149,647	13,011	0.1050
24	2RS2A-Residential Submeter	3,212	308,044	227	14,150	0.0959
25	2RS3A-Residential Sep Heat	14,496	1,277,547	1,114	13,013	0.0881
26	2RS6A-Residential Elec Heat	369,522	30,932,252	22,496	16,426	0.0837
27	2RSDA-Residential Standard 3PH	1,769	173,634	34	52,029	0.0982
28	2RW1A-Residential Water Heat	51,666	4,755,663	3,731	13,848	0.0920
29	2RW2A-Res Water/Space Heat	11,730	928,172	803	14,608	0.0791
30	2RW3A-Res Water/Space Heat	195,748	15,068,342	10,626	18,422	0.0770
31	2RW6A-Res Water/Space Heat	379,181	29,682,701	23,776	15,948	0.0783
32	2RW7A-Res Water/Space Heat	1,728	134,457	51	33,882	0.0778
33	2TE1A-Residential Time of Day	859	82,626	58	14,810	0.0962
34	Fuel Clause Accrual		4,035,604			
35	Unbilled Revenue	5,640	299,662			0.0531
36	Total KS Residential	2,983,778	292,445,036	214,576	13,905	0.0980
37						
38						
39						
40						
41	TOTAL Billed	15,442,779	1,308,450,784	519,616	29,720	0.0847
42	Total Unbilled Rev.(See Instr. 6)	24,214	3,601,149	0	0	0.1487
43	TOTAL	15,466,993	1,312,051,933	519,616	29,766	0.0848

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	1ALDE-Area Lighting	13,263	2,486,225	2,353	5,637	0.1875
2	1LGAE-Large General All Elec	671,345	47,775,092	211	3,181,730	0.0712
3	1LGAF-Large General All Elec	191,101	12,538,434	14	13,650,071	0.0656
4	1LGHE-Large General Heat	52,141	4,134,101	34	1,533,559	0.0793
5	1LGSE-Large General Service	972,482	76,769,293	620	1,568,519	0.0789
6	1LGSF-Large General Service	157,047	11,752,710	49	3,205,041	0.0748
7	1LSHE-Large General Heat	2,936	254,664	2	1,468,000	0.0867
8	1MGAE-Medium General All Elec	129,669	10,336,244	428	302,965	0.0797
9	1MGAF-Medium General All Elec	1,056	96,813	2	528,000	0.0917
10	1MGHE-Medium General Heat	24,670	2,103,168	93	265,269	0.0853
11	1MGSE-Medium General Service	870,540	78,488,758	4,365	199,436	0.0902
12	1MGSF-Medium General Service	7,188	691,645	27	266,222	0.0962
13	1MSHE-Medium General Heat	162	16,845	1	162,000	0.1040
14	1MSEE-Medium General Service	24,993	2,635,676	161	155,236	0.1055
15	1PGSE-Large Power Service	356,568	22,167,864	25	14,262,720	0.0622
16	1PGSF-Large Power Service	416,848	28,054,374	23	18,123,826	0.0673
17	1POSF-Large Power Off Peak	147,613	9,521,113	8	18,451,625	0.0645
18	1POSW-Large Power Off Peak	28,452	1,488,671	1	28,452,000	0.0523
19	1SGAE-Small General All Elec	18,579	1,921,529	566	32,825	0.1034
20	1SGHE-Small General Heat	6,549	714,797	258	25,384	0.1091
21	1SGSE-Small General Service	358,664	42,502,513	22,435	15,987	0.1185
22	1SGSF-Small General Service	821	147,743	33	24,879	0.1800
23	1SSAE-Small General All Elec	112	12,040	6	18,667	0.1075
24	1SSHE-Small General Heat	956	110,456	15	63,733	0.1155
25	1SSSE-Small General Service	12,014	1,693,487	564	21,301	0.1410
26	1SUSE-Small General Unmetered	7,530	967,643	1,217	6,187	0.1285
27	Excess Gross Margin		205,440			
28	Unbilled Revenue	4,839	463,964			0.0959
29	Total MO Commercial	4,478,138	360,051,302	33,511	133,632	0.0804
30						
31	2ALDE-Area Lighting	2,169	500,144	764	2,839	0.2306
32	2LGAE-Large General Space Heat	709,944	43,908,483	298	2,382,362	0.0618
33	2LGAF-Large General Space Heat	11,244	432,989	2	5,622,000	0.0385
34	2LGHE-Large General Heat	95,599	6,603,452	62	1,541,919	0.0691
35	2LGSE-Large General Service	1,024,233	73,606,807	640	1,600,364	0.0719
36	2LGSF-Large General Service	221,692	14,253,446	33	6,717,939	0.0643
37	2LS1E-Off Peak Light Service	36,002	2,089,842	1,373	26,221	0.0580
38	2MGAE-Medium Gen Space Heat	99,694	7,541,218	385	258,945	0.0756
39	2MGHE-Medium General Heat	19,300	1,666,029	102	189,216	0.0863
40	2MGSE-Medium General Service	596,860	53,884,406	3,373	176,952	0.0903
41	TOTAL Billed	15,442,779	1,308,450,784	519,616	29,720	0.0847
42	Total Unbilled Rev.(See Instr. 6)	24,214	3,601,149	0	0	0.1487
43	TOTAL	15,466,993	1,312,051,933	519,616	29,766	0.0848

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	2MGSF-Medium General Service	393	59,050	3	131,000	0.1503
2	2MLIK-Commercial St Light	1	166	1	1,000	0.1660
3	2MLSK-Commercial St Light HP	2	585	1	2,000	0.2925
4	2PGSW-Large Power Service	92,608	4,665,594	1	92,608,000	0.0504
5	2SGAE-Small Gen Space Heat	22,019	2,142,532	1,131	19,469	0.0973
6	2SGAF-Small Gen Space Heat	8	944	2	4,000	0.1180
7	2SGHE-Small General Heat	11,344	1,145,502	403	28,149	0.1010
8	2SGSE-Small General Service	273,332	30,636,299	18,043	15,149	0.1121
9	2SGSF-Small General Service	28	2,802	2	14,000	0.1001
10	2SUSE-Small General Unmetered	2,781	440,751	957	2,906	0.1585
11	Wind Generation	-1	452			-0.4520
12	Fuel Clause Accrual		4,238,704			
13	Unbilled Revenue	8,110	592,244			0.0730
14	Total KS Commercial	3,227,362	248,412,441	27,576	117,035	0.0770
15						
16	1LGAH-Large General All Elec	36,723	2,254,263	7	5,246,143	0.0614
17	1LGHH-Large General Heat	9,567	656,936	2	4,783,500	0.0687
18	1LGSG-Large General Service	65,808	5,528,015	22	2,991,273	0.0840
19	1LGSH-Large General Service	130,057	10,527,355	87	1,494,908	0.0809
20	1MGAH-Medium General All Elec	3,942	343,749	12	328,500	0.0872
21	1MGHH-Medium General w/Heat	286	28,348	2	143,000	0.0991
22	1MGSG-Medium General Service	5,215	435,457	9	579,444	0.0835
23	1MGSH-Medium General Service	53,871	5,382,968	298	180,775	0.0999
24	1PGSG-Large Power Service	472,086	26,162,534	14	33,720,429	0.0554
25	1PGSH-Large Power Service	63,867	4,323,093	7	9,123,857	0.0677
26	1PGSV-Large Power Service	404,707	20,053,877	3	134,902,333	0.0496
27	1PGSZ-Large Power Service	96,491	5,424,969	2	48,245,500	0.0562
28	1POSG-Large Power Off Peak	126,316	7,092,568	3	42,105,333	0.0561
29	1POSZ-Large Power Off Peak	113,323	5,685,740	1	113,323,000	0.0502
30	1SGAH-Small General All Elec	238	31,867	8	29,750	0.1339
31	1SGHH-Small General Heat	40	3,113	1	40,000	0.0778
32	1SGAG-Small General Service	113	12,888	4	28,250	0.1141
33	1SGSH-Small General Service	10,350	1,302,943	599	17,279	0.1259
34	Excess Gross Margin		71,826			
35	Unbilled Revenue	1,430	95,706			0.0669
36	Total MO Industrial	1,594,430	95,418,215	1,081	1,474,958	0.0598
37						
38						
39						
40						
41	TOTAL Billed	15,442,779	1,308,450,784	519,616	29,720	0.0847
42	Total Unbilled Rev.(See Instr. 6)	24,214	3,601,149	0	0	0.1487
43	TOTAL	15,466,993	1,312,051,933	519,616	29,766	0.0848

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	2LGAH-Large General Space Heat	24,281	1,680,243	11	2,207,364	0.0692
2	2LGHH-Large General Heat	1,222	84,486	1	1,222,000	0.0691
3	2LGSG-Large General Service	45,313	2,991,993	9	5,034,778	0.0660
4	2LGSH-Large General Service	173,995	12,342,322	64	2,718,672	0.0709
5	2MGAH-Medium Gen Space Heat	2,471	251,730	5	494,200	0.1019
6	2MGHH-Medium General Heat	421	40,109	2	210,500	0.0953
7	2MGSH-Medium General Service	23,742	2,295,219	143	166,028	0.0967
8	2PGSG-Large Power Service	54,469	3,132,032	1	54,469,000	0.0575
9	2PGSV-Large Power Service	19,731	1,115,499	1	19,731,000	0.0565
10	2SGAH-Small General Space Heat	350	36,417	14	25,000	0.1040
11	2SGHH-Small General Heat	215	25,240	6	35,833	0.1174
12	2SGSG-Small General Service		187	1		
13	2SGSH-Small General Service	15,181	1,519,404	740	20,515	0.1001
14	Ash Grove Aggregate		-9,880			
15	Fuel Clause Accrual		475,479			
16	Unbilled Revenue	-305	1,834,745			-6.0156
17	Total KS Industrial	361,086	27,815,225	998	361,810	0.0770
18						
19	1MLCL-Municipal St Light	226	37,151	1	226,000	0.1644
20	1MLML-Municipal St Light MV	8	1,847	4	2,000	0.2309
21	1MLSL-Municipal St Light HP	3,629	1,164,258	17	213,471	0.3208
22	1TSLM-Traffic Signal Light	119	44,683	2	59,500	0.3755
23	3MLCL-Municipal St Light	65	10,675	8	8,125	0.1642
24	3MLML-Municipal St Light MV	1	205	1	1,000	0.2050
25	3MLSL-Municipal St Light HP	1,713	414,012	37	46,297	0.2417
26	Kansas City Parks	-5	-256			0.0512
27	KCMO School Parking Lots	646	40,457			0.0626
28	Kansas City St Lights	63,960	4,078,123			0.0638
29	Excess Gross Margin		3,268			
30	Total MO Public Street Lights	70,362	5,794,423	70	1,005,171	0.0824
31						
32	2MLCL-Municipal St Light	7	1,295	1	7,000	0.1850
33	2MLIL-Municipal St Light	127	21,464	15	8,467	0.1690
34	2MLML-Municipal St Light MV	812	154,316	27	30,074	0.1900
35	2MLSL-Municipal St Light HP	13,092	4,563,682	45	290,933	0.3486
36	2MOSL-Municipal St Light	44	46,832	2	22,000	1.0644
37	2TSLM-Traffic Signal Light	2,689	1,241,873	13	206,846	0.4618
38	Fuel Clause Accrual		20,306			
39	Total KS Public Street Lights	16,771	6,049,768	103	162,825	0.3607
40						
41	TOTAL Billed	15,442,779	1,308,450,784	519,616	29,720	0.0847
42	Total Unbilled Rev.(See Instr. 6)	24,214	3,601,149	0	0	0.1487
43	TOTAL	15,466,993	1,312,051,933	519,616	29,766	0.0848

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Instruction Note (5)					
2	Fuel Clause Revenue Billed					
3	Residential		32,781,750			
4	Commercial		34,264,027			
5	Industrial		3,813,049			
6	Public Street Lights		169,252			
7	Total Fuel Clause Revenue Billed		71,028,078			
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
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35						
36						
37						
38						
39						
40						
41	TOTAL Billed	15,442,779	1,308,450,784	519,616	29,720	0.0847
42	Total Unbilled Rev.(See Instr. 6)	24,214	3,601,149	0	0	0.1487
43	TOTAL	15,466,993	1,312,051,933	519,616	29,766	0.0848

Name of Respondent Kansas City Power & Light Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Schedule Page: 304 Line No.: 41 Column: d

Note: The average number of customers reported on page 301 is the number of bills rendered, per premise, during the year divided by 12 periods. However, on page 304, some customers are served under more than one rate.

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).

2. Enter the name of the purchaser in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
 RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
 LF - for long-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
 IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
 SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
 LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
 IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	FULL REQUIREMENTS SALES FOR					
2	Kansas Electric Power Coop.	RQ	WSPP, Sch.A	18.661	16.422	
3	City of Pomona, Kansas	RQ	WSPP, Sch.A	2.303	2.027	
4	City of Prescott, Kansas	RQ	WSPP, Sch.A	.575	.506	
5	City of Slater, Missouri	RQ	WSPP, Sch.A	5.518	4.856	
6	KCP&L GMO	RQ	WSPP, Sch.A	1.152	1.014	
7	KCP&L GMO	RQ	129			
8						
9						
10						
11						
12						
13						
14	BULK POWER SALES					
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).

2. Enter the name of the purchaser in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
 RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
 LF - for long-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
 IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
 SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
 LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
 IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	The Energy Authority	OS	MEMA, Sch.M			
2	Union Electric Company	OS	WSPP, Sch.A			
3	Union Power Partners, LP	OS	WSPP, Sch.A			
4	Westar Energy, Inc.	OS	WSPP, Sch.A			
5	Westar Energy, Inc.	OS	MEMA, Sch.M			
6	Western Area Power Administration	OS	MEMA, Sch.M			
7	Western Farmers Electric Cooperative	OS	WSPP, Sch.A			
8	ACCOUNTING ADJUSTMENTS					
9	Elimination of inter-co transactions					
10	Accounting Reclass					
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.

AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)

5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401, line 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
					1
75,428		4,351,562		4,351,562	2
8,223		458,726		458,726	3
2,088		122,436		122,436	4
20,981		1,122,857		1,122,857	5
5,182	16,339	174,976		191,315	6
1,521		18,753		18,753	7
					8
					9
					10
					11
					12
					13
					14
113,423	16,339	6,249,310	0	6,265,649	
5,937,524	11,205,000	219,434,698	-48,029,812	182,609,886	
6,050,947	11,221,339	225,684,008	-48,029,812	188,875,535	

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.

AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)

5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)

demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401, line 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
2,508		67,409		67,409	1
98,177		2,888,149		2,888,149	2
49,666		1,698,081		1,698,081	3
66,397		1,779,664		1,779,664	4
334,886		8,783,127		8,783,127	5
					6
					7
41		2,073		2,073	8
8		200		200	9
1,558		22,676		22,676	10
321,451		7,919,038		7,919,038	11
3,298		117,119		117,119	12
249,558		8,484,972	2,730,000	11,214,972	13
361,558	3,825,000	7,294,628		11,119,628	14
113,423	16,339	6,249,310	0	6,265,649	
5,937,524	11,205,000	219,434,698	-48,029,812	182,609,886	
6,050,947	11,221,339	225,684,008	-48,029,812	188,875,535	

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.

AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)

5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401, line 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
1,056		43,203		43,203	1
327,209		9,168,884		9,168,884	2
73,996		1,981,331		1,981,331	3
25,662		912,326		912,326	4
44,299		1,084,714		1,084,714	5
169,640		4,413,771	35,343	4,449,114	6
9,841		236,584		236,584	7
4		230		230	8
4,838		167,712	320,966	488,678	9
503,532	7,380,000	11,614,519		18,994,519	10
42,498		1,174,208		1,174,208	11
7,226		189,286		189,286	12
12,126		287,215		287,215	13
26,722		733,803	1,980,924	2,714,727	14
113,423	16,339	6,249,310	0	6,265,649	
5,937,524	11,205,000	219,434,698	-48,029,812	182,609,886	
6,050,947	11,221,339	225,684,008	-48,029,812	188,875,535	

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.

AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)

5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)

demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401, line 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
1,566,557		61,825,535		61,825,535	1
		123,888		123,888	2
7		252		252	3
3,267		106,511		106,511	4
7		271		271	5
36,280		1,256,005		1,256,005	6
430,035		9,916,399		9,916,399	7
435,996		18,311,832		18,311,832	8
84		8,820		8,820	9
1,839		57,631		57,631	10
93		3,460		3,460	11
268,476		9,591,403		9,591,403	12
281		15,352		15,352	13
6,456		118,865		118,865	14
113,423	16,339	6,249,310	0	6,265,649	
5,937,524	11,205,000	219,434,698	-48,029,812	182,609,886	
6,050,947	11,221,339	225,684,008	-48,029,812	188,875,535	

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.

AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)

5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)

demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401, line 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
7,665		233,010		233,010	1
588		25,624	-53,199	-27,575	2
3,200		80,800		80,800	3
568		6,496		6,496	4
51,494		1,612,852		1,612,852	5
95		4,236		4,236	6
37,000		949,262		949,262	7
		608,719		608,719	8
22		1,326		1,326	9
36,970		797,501		797,501	10
1,302,315		34,254,036		34,254,036	11
10,146		290,628		290,628	12
130,813		3,962,987		3,962,987	13
27,853		703,600		703,600	14
113,423	16,339	6,249,310	0	6,265,649	
5,937,524	11,205,000	219,434,698	-48,029,812	182,609,886	
6,050,947	11,221,339	225,684,008	-48,029,812	188,875,535	

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.

AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)

5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type-of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401, line 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
15,433		516,494		516,494	1
9,198		240,680		240,680	2
6		198		198	3
52,517		1,118,763		1,118,763	4
6,686		278,994		278,994	5
6,654		136,660		136,660	6
43,444		1,210,686		1,210,686	7
					8
-1,292,276			-53,110,713	-53,110,713	9
			66,867	66,867	10
					11
					12
					13
					14
113,423	16,339	6,249,310	0	6,265,649	
5,937,524	11,205,000	219,434,698	-48,029,812	182,609,886	
6,050,947	11,221,339	225,684,008	-48,029,812	188,875,535	

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report 2010/Q4
Kansas City Power & Light Company			
FOOTNOTE DATA			

Schedule Page: 310 Line No.: 6 Column: a

Great Plains Energy, the parent company of Kansas City Power & Light Company, also owns all the outstanding shares of KCPL GMO and its Missouri-based electric utility assets.

Schedule Page: 310 Line No.: 7 Column: a

Great Plains Energy, the parent company of Kansas City Power & Light Company, also owns all the outstanding shares of KCPL GMO and its Missouri-based electric utility assets.

Schedule Page: 310 Line No.: 7 Column: b

Bates County agreement termination date 10/1/2010

Schedule Page: 310.1 Line No.: 1 Column: b

Hour by hour economy power interchanges for all statistic classes of OS.

Schedule Page: 310.1 Line No.: 13 Column: a

Termination date of 12/31/2014

Schedule Page: 310.1 Line No.: 14 Column: a

LU Service - Market Based Sales Tariff - provided by the City of Springfield from Kansas City Power & Light's Montrose Station. Service is provided from 2001-2013 as specified in the Power Sales Agreement, Amendatory Agreement No. 1 (FPC No. 46).

Schedule Page: 310.2 Line No.: 9 Column: a

Non-LF Service - Supplemental Regulation Service Agreement with the City of Independence, MO, July 1, 2008 through December 31, 2012, and year-to-year thereafter.

Schedule Page: 310.2 Line No.: 10 Column: a

Capacity Exchange Service provided to City of Independence from Kansas City Power & Light's Montrose Station. Service is provided from 1996-2011 as specified in the Municipal Participation Agreement, Amendatory Agreement No. 8 (FERC 101).

Schedule Page: 310.3 Line No.: 1 Column: a

Great Plains Energy, the parent company of Kansas City Power & Light Company, also owns all the outstanding shares of KCPL GMO and its Missouri-based electric utility assets.

Schedule Page: 310.3 Line No.: 2 Column: a

Kansas City Power & Light Trans is Kansas City Power & Light's Transmission Department. This is to record the value of losses attributable to the amount Kansas City Power & Light's Transmission Department collected related to the increase in Generation provided for losses.

Schedule Page: 310.4 Line No.: 8 Column: a

Southwest Power Pool is a provider of Transmission Service and collects loss revenue related to the sales of transmission service where KCP&L's Generators provide losses.

Schedule Page: 310.4 Line No.: 11 Column: a

Southwest Power Pool RTO Energy Markets Tariff. Market start date February 1, 2007.

Schedule Page: 310.5 Line No.: 9 Column: a

Elimination of activity between KCP&L and KCP&L GMO.

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	9,965,723	9,136,142
5	(501) Fuel	232,312,462	218,502,765
6	(502) Steam Expenses	16,168,029	15,609,179
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	6,697,821	6,520,926
10	(506) Miscellaneous Steam Power Expenses	9,889,866	10,595,342
11	(507) Rents	194,946	146,172
12	(509) Allowances	-140,103	
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	275,088,744	260,510,526
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	6,132,000	5,841,667
16	(511) Maintenance of Structures	5,517,656	4,404,072
17	(512) Maintenance of Boiler Plant	31,936,360	25,832,366
18	(513) Maintenance of Electric Plant	5,505,127	3,713,112
19	(514) Maintenance of Miscellaneous Steam Plant	358,541	186,513
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	49,449,684	39,977,730
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	324,538,428	300,488,256
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	5,964,702	6,065,017
25	(518) Fuel	29,169,655	20,016,098
26	(519) Coolants and Water	2,356,535	2,447,327
27	(520) Steam Expenses	9,963,704	13,044,482
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	890,864	931,434
31	(524) Miscellaneous Nuclear Power Expenses	26,615,136	21,563,483
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	74,960,596	64,067,841
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	3,746,591	6,924,082
36	(529) Maintenance of Structures	2,194,789	2,133,684
37	(530) Maintenance of Reactor Plant Equipment	16,273,622	4,599,469
38	(531) Maintenance of Electric Plant	2,825,079	4,251,519
39	(532) Maintenance of Miscellaneous Nuclear Plant	2,164,636	2,391,381
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	27,204,717	20,300,135
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	102,165,313	84,367,976
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)		

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	1,153,746	1,780,264
63	(547) Fuel	17,505,409	12,732,764
64	(548) Generation Expenses	1,602,339	1,213,565
65	(549) Miscellaneous Other Power Generation Expenses	292,120	7,819,244
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	20,553,614	23,545,837
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	1,173,027	1,932,148
70	(552) Maintenance of Structures	235,317	68,920
71	(553) Maintenance of Generating and Electric Plant	820,810	893,598
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	126,952	35,684
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	2,356,106	2,930,350
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	22,909,720	26,476,187
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	78,910,777	70,799,230
77	(556) System Control and Load Dispatching	2,537,017	1,901,852
78	(557) Other Expenses	6,662,962	4,406,027
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	88,110,756	77,107,109
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	537,724,217	488,439,528
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	1,485,692	1,689,989
84	(561) Load Dispatching	20,380	37,318
85	(561.1) Load Dispatch-Reliability	38	
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	521,936	512,493
87	(561.3) Load Dispatch-Transmission Service and Scheduling	215,108	173,863
88	(561.4) Scheduling, System Control and Dispatch Services	3,409,841	2,498,396
89	(561.5) Reliability, Planning and Standards Development		23,520
90	(561.6) Transmission Service Studies	143,371	13,073
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	474,884	326,742
93	(562) Station Expenses	287,943	300,630
94	(563) Overhead Lines Expenses	176,265	232,783
95	(564) Underground Lines Expenses	910	17
96	(565) Transmission of Electricity by Others	15,022,326	12,349,274
97	(566) Miscellaneous Transmission Expenses	1,951,143	2,014,844
98	(567) Rents	2,380,688	2,424,391
99	TOTAL Operation (Enter Total of lines 83 thru 98)	26,090,525	22,597,333
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	75	14,145
102	(569) Maintenance of Structures	36,463	27,542
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software		
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	581,672	497,463
108	(571) Maintenance of Overhead Lines	3,786,686	1,919,140
109	(572) Maintenance of Underground Lines	11,271	128,063
110	(573) Maintenance of Miscellaneous Transmission Plant	19,752	
111	TOTAL Maintenance (Total of lines 101 thru 110)	4,435,919	2,586,353
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	30,526,444	25,183,686

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation	8,576	34,200
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	2,454,386	2,462,502
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	2,462,962	2,496,702
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	2,462,962	2,496,702
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	4,727,879	2,579,175
135	(581) Load Dispatching	1,004,108	1,032,010
136	(582) Station Expenses	434,834	512,108
137	(583) Overhead Line Expenses	1,129,517	1,485,854
138	(584) Underground Line Expenses	1,759,671	2,004,864
139	(585) Street Lighting and Signal System Expenses	5,778	12,147
140	(586) Meter Expenses	1,538,427	1,575,926
141	(587) Customer Installations Expenses	260,942	399,516
142	(588) Miscellaneous Expenses	13,215,792	12,855,101
143	(589) Rents	47,277	47,287
144	TOTAL Operation (Enter Total of lines 134 thru 143)	24,124,225	22,503,988
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	53,842	70,834
147	(591) Maintenance of Structures	1,377,698	1,141,122
148	(592) Maintenance of Station Equipment	1,089,521	806,804
149	(593) Maintenance of Overhead Lines	15,033,258	16,776,706
150	(594) Maintenance of Underground Lines	1,019,660	2,273,338
151	(595) Maintenance of Line Transformers	738,529	1,102,889
152	(596) Maintenance of Street Lighting and Signal Systems	1,245,977	1,291,246
153	(597) Maintenance of Meters	522,421	439,900
154	(598) Maintenance of Miscellaneous Distribution Plant	724,685	345,080
155	TOTAL Maintenance (Total of lines 146 thru 154)	21,805,591	24,247,919
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	45,929,816	46,751,907
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	1,216,351	1,307,478
160	(902) Meter Reading Expenses	4,018,061	4,081,210
161	(903) Customer Records and Collection Expenses	12,408,902	12,163,465
162	(904) Uncollectible Accounts		
163	(905) Miscellaneous Customer Accounts Expenses	963,071	2,371
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	18,606,385	17,554,524

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	364,513	351,176
168	(908) Customer Assistance Expenses	9,574,811	7,332,663
169	(909) Informational and Instructional Expenses	197,239	26,533
170	(910) Miscellaneous Customer Service and Informational Expenses	1,858,358	793,492
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	11,994,921	8,503,864
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision	34,115	77,055
175	(912) Demonstrating and Selling Expenses	548,747	783,673
176	(913) Advertising Expenses	1,024	13,546
177	(916) Miscellaneous Sales Expenses	94,045	100,872
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	677,931	975,146
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	40,562,879	41,428,417
182	(921) Office Supplies and Expenses	1,082,668	1,719,630
183	(Less) (922) Administrative Expenses Transferred-Credit	6,443,760	7,785,174
184	(923) Outside Services Employed	9,902,614	9,989,087
185	(924) Property Insurance	3,291,185	2,825,832
186	(925) Injuries and Damages	8,656,710	6,873,749
187	(926) Employee Pensions and Benefits	66,520,109	60,579,650
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	10,783,361	6,676,498
190	(929) (Less) Duplicate Charges-Cr.	65,043	-131
191	(930.1) General Advertising Expenses	340,880	238,994
192	(930.2) Miscellaneous General Expenses	7,168,671	6,966,469
193	(931) Rents	7,104,691	7,931,737
194	TOTAL Operation (Enter Total of lines 181 thru 193)	148,904,965	137,445,020
195	Maintenance		
196	(935) Maintenance of General Plant	3,833,950	4,648,251
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	152,738,915	142,093,271
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	800,661,591	731,998,628

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Kansas City Power & Light Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 04/15/2011	2010/Q4
FOOTNOTE DATA			

Schedule Page: 320 Line No.: 98 Column: b

Per Docket No. ER10-230-000, FERC transmission formula rate, additional detail for lease expense has been provided below:

CFSI Joint & Terminal Facility Charge	202,123
Cooper-Fairpoint - St. Joe-Billing for Share	249,702
WC Line Lease	1,895,076
Total KCPL Transmission Lease Expense	2,346,901
All Other	33,787
Total KCPL Account 567000	2,380,688

Schedule Page: 320 Line No.: 98 Column: c

Per Docket No. ER10-230-000, FERC transmission formula rate, additional detail for lease expense has been provided below:

CFSI Joint & Terminal Facility Charge	202,123
Cooper-Fairpoint - St. Joe-Billing for Share	236,587
WC Line Lease	1,952,356
Total KCPL Transmission Lease Expense	2,391,066
All Other	33,325
Total KCPL Account 567000	2,424,391

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Ameren Energy Marketing Company	OS	WSPP, Sch.A	N/A	N/A	N/A
2	American Electric Power	OS	WSPP, Sch.A	N/A	N/A	N/A
3	American Electric Power	OS	EEl Agreement	N/A	N/A	N/A
4	Associated Electric Cooperative	OS	WSPP, Sch.A	N/A	N/A	N/A
5	Associated Electric Cooperative	IF	WSPP, Sch.C	N/A	N/A	N/A
6	Associated Electric Cooperative	RQ	107	N/A	N/A	N/A
7	Black Hills Power, Inc.	OS	WSPP, Sch.A	N/A	N/A	N/A
8	Board of Public Utilities	OS	WSPP, Sch.A	N/A	N/A	N/A
9	Board of Public Utilities	RQ	109	N/A	N/A	N/A
10	BP Energy Company	OS	WSPP, Sch.A	N/A	N/A	N/A
11	Calpine Energy Services, LP	OS	WSPP, Sch.A	N/A	N/A	N/A
12	Cargill Power Markets, LLC	OS	WSPP, Sch.A	N/A	N/A	N/A
13	Citigroup Energy, Inc.	OS	WSPP, Sch.A	N/A	N/A	N/A
14	City of Higginsville, MO	LU	108	N/A	N/A	N/A
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	City of Sikeston, MO	OS	WSPP, Sch.A	N/A	N/A	N/A
2	Cleco Power, LLC	OS	WSPP, Sch.A	N/A	N/A	N/A
3	ConocoPhillips Company	OS	WSPP, Sch.A	N/A	N/A	N/A
4	Constellation Energy Commodities Gp.	OS	WSPP, Sch.A	N/A	N/A	N/A
5	Electric Reliability Council of Texas	OS	ERCOT RTO	N/A	N/A	N/A
6	Empire District Electric Company	OS	WSPP, Sch.A	N/A	N/A	N/A
7	Endure Energy, LLC	OS	WSPP, Sch.A	N/A	N/A	N/A
8	Entergy Services, Inc.	OS	WSPP, Sch.A	N/A	N/A	N/A
9	Exelon Generation Company LLC	OS	WSPP, Sch.A	N/A	N/A	N/A
10	Grand River Dam Authority	OS	WSPP, Sch.A	N/A	N/A	N/A
11	Independence Power & Light	OS	WSPP, Sch.A	N/A	N/A	N/A
12	Independence Power & Light	OS	WSPP, Sch.A	N/A	N/A	N/A
13	Independence Power & Light	RQ	WSPP, Sch.A	N/A	N/A	N/A
14	JP Morgan Ventures Energy Corporation	OS	EEl Agreement	N/A	N/A	N/A
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Kansas Energy LLC	OS	MEMA, Sch.M	N/A	N/A	N/A
2	Kansas Municipal Energy Agency	OS	118	N/A	N/A	N/A
3	KC District Energy (Trigen)	OS	N/A	N/A	N/A	N/A
4	KCP&L Greater Missouri Operations Co	RQ	47	N/A	N/A	N/A
5	KCP&L Greater Missouri Operations Co	OS	WSPP, Sch.A	N/A	N/A	N/A
6	Lafayette Utilities System	OS	WSPP, Sch.A	N/A	N/A	N/A
7	Lighthouse Energy Trading	OS	MEMA, Sch.M	N/A	N/A	N/A
8	Lincoln Electric System	OS	MEMA, Sch.M	N/A	N/A	N/A
9	Louisiana Energy and Power Authority	OS	WSPP, Sch.A	N/A	N/A	N/A
10	Macquarie Energy LLC	OS	WSPP, Sch.A	N/A	N/A	N/A
11	MidAmerican Energy Company	OS	MEMA, Sch.K	N/A	N/A	N/A
12	Midwest Independent System Operator	OS	MISO RTO	N/A	N/A	N/A
13	MO Joint Muni Elec Util Commission	OS	WSPP, Sch.A	N/A	N/A	N/A
14	Morgan Stanley Capital Group Inc.	OS	WSPP, Sch.A	N/A	N/A	N/A
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Morgan Stanley Capital Group Inc.	LF	WSPP, Sch.A	N/A	N/A	N/A
2	Municipal Energy Agency of NE	OS	MEMA, Sch.M	N/A	N/A	N/A
3	Nebraska Public Power District	OS	MEMA, Sch.M	N/A	N/A	N/A
4	NRG Power Marketing Inc.	OS	MEMA, Sch.M	N/A	N/A	N/A
5	Oklahoma Gas & Electric	OS	WSPP, Sch.A	N/A	N/A	N/A
6	Oklahoma Municipal Power Authority	OS	WSPP, Sch.A	N/A	N/A	N/A
7	Omaha Public Power District	OS	MEMA, Sch.M	N/A	N/A	N/A
8	PJM Interconnection LLC	OS	PJM RTO	N/A	N/A	N/A
9	Powerex Corp.	OS	WSPP, Sch.A	N/A	N/A	N/A
10	Public Service Company of Colorado	OS	WSPP, Sch.A	N/A	N/A	N/A
11	Rainbow Energy Marketing Corporation	OS	MEMA, Sch.M	N/A	N/A	N/A
12	South Mississippi Elec Pwr Assoc.	OS	WSPP, Sch.A	N/A	N/A	N/A
13	Southwestern Power Administration	OS	WSPP, Sch.A	N/A	N/A	N/A
14	Southwestern Public Service Company	OS	SPS ECST	N/A	N/A	N/A
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

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SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Southwestern Public Service Company	OS	SPS ATT S	N/A	N/A	N/A
2	Southwest Power Pool	OS	SPP RTO	N/A	N/A	N/A
3	Sunflower Electric Power Corporation	OS	WSPP, Sch.A	N/A	N/A	N/A
4	Tenaska Power Services Company	OS	MEMA, Sch.M	N/A	N/A	N/A
5	The Energy Authority	OS	MEMA, Sch.M	N/A	N/A	N/A
6	Union Electric Company	OS	WSPP, Sch.A	N/A	N/A	N/A
7	Union Power Partners, LP	OS	WSPP, Sch.A	N/A	N/A	N/A
8	Westar Energy Inc.	OS	MEMA, Sch.M	N/A	N/A	N/A
9	Westar Energy Inc.	OS	WSPP, Sch.A	N/A	N/A	N/A
10	Western Area Power Administration	OS	MEMA, Sch.M	N/A	N/A	N/A
11	Western Farmers Electric Cooperative	OS	WSPP, Sch.A	N/A	N/A	N/A
12	ACCOUNTING ADJUSTMENTS					
13	Elimination of inter-co transactions					
14	Iatan 2 displacement					
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

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EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Accounting reclass					
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
25,044				1,198,609		1,198,609	1
16,250				1,397,069		1,397,069	2
40,694				1,972,942		1,972,942	3
114,510				5,906,467		5,906,467	4
54,523			2,175,000	3,505,122		5,680,122	5
				109,792		109,792	6
2,698				137,260		137,260	7
57				4,088		4,088	8
18,648				758,210		758,210	9
8				200		200	10
174,350				8,268,850		8,268,850	11
64,327				2,719,990		2,719,990	12
6,559				300,439		300,439	13
242			2,881,800	31,923		2,913,723	14
1,458,839			7,380,476	71,530,301		78,910,777	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
15,605				625,109		625,109	1
1,445				56,715		56,715	2
451				22,858		22,858	3
2,840				70,671		70,671	4
20,299				536,161		536,161	5
23,151				760,725		760,725	6
46,150				2,331,815		2,331,815	7
3,493				242,473		242,473	8
116,788				5,538,005		5,538,005	9
30,598				1,441,048		1,441,048	10
23				1,408		1,408	11
4,336				144,412		144,412	12
2,663				126,472		126,472	13
6,645				282,154		282,154	14
1,458,839			7,380,476	71,530,301		78,910,777	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
350				21,000		21,000	1
4,819				45,705		45,705	2
5,328				58,871		58,871	3
588				7,353		7,353	4
54,251				1,850,319		1,850,319	5
35				2,191		2,191	6
1,045				62,793		62,793	7
73				1,387		1,387	8
31				1,945		1,945	9
675				27,825		27,825	10
20,448			576,875	954,240		1,531,115	11
62,804				2,007,970		2,007,970	12
20				300		300	13
84				6,629		6,629	14
1,458,839			7,380,476	71,530,301		78,910,777	

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
1,445			1,746,801	114,039		1,860,840	1
9,033				281,616		281,616	2
3,190				97,771		97,771	3
12,968				649,574		649,574	4
796				36,350		36,350	5
17,228				680,178		680,178	6
217,165				7,188,651		7,188,651	7
				557		557	8
1,201				42,827		42,827	9
1,218				71,660		71,660	10
34,542				1,256,752		1,256,752	11
187				11,397		11,397	12
274				13,910		13,910	13
23,942				1,127,175		1,127,175	14
1,458,839			7,380,476	71,530,301		78,910,777	

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
698				35,132		35,132	1
64,130				3,763,194		3,763,194	2
866				26,234		26,234	3
152,828				6,663,428		6,663,428	4
311,520				11,084,148		11,084,148	5
163,889				7,105,628		7,105,628	6
11,283				684,745		684,745	7
148,707				7,722,675		7,722,675	8
360,006				15,791,955		15,791,955	9
55,956				2,060,850		2,060,850	10
1,162				47,991		47,991	11
							12
-1,292,276				-53,110,713		-53,110,713	13
213,933				14,553,635		14,553,635	14
1,458,839			7,380,476	71,530,301		78,910,777	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
				-10,573		-10,573	1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
1,458,839			7,380,476	71,530,301		78,910,777	

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report 2010/Q4
Kansas City Power & Light Company			
FOOTNOTE DATA			

Schedule Page: 326 Line No.: 1 Column: a

Hour by hour economy power interchange for all statistical class of OS.

Schedule Page: 326 Line No.: 5 Column: a

KCP&L purchases firm capacity and energy from Associated Electric Cooperative, Inc., under the Capacity and Energy Confirmation dated August 25, 2005, under WSPP Service Schedule C, from June 1, 2006 to May 31, 2010.

Schedule Page: 326 Line No.: 6 Column: a

Per mint line agreement dated March 5, 1990.

Schedule Page: 326 Line No.: 9 Column: a

Border Customer.

Schedule Page: 326 Line No.: 14 Column: a

KCP&L purchases firm capacity and energy from the City of Higginsville, MO, from June 1, 1996 through May 31, 2016 per the Revised and Restated Amendatory Agreement No. 1 to the Municipal Participation Agreement, First Revised Rate Schedule FERC No. 108.

Schedule Page: 326.1 Line No.: 12 Column: a

Non LF Service - Supplemental Regulation Service Agreement with the City of Independence, MO, July 1, 2008, through December 31, 2012, and year-to-year thereafter.

Schedule Page: 326.1 Line No.: 13 Column: a

Border customer.

Schedule Page: 326.2 Line No.: 2 Column: a

KCP&L purchases load following energy service from Kansas Municipal Energy Agency from June 1, 2009 through May 31, 2012, per the KMEA Load Following Energy Confirmation dated July 21, 2009, referencing KMEA's Interchange Agreement, Service Schedule B, Term Energy, Supplement No. 2 to KCPL's FERC No. 118.

Schedule Page: 326.2 Line No.: 4 Column: a

Great Plains Energy, the parent company of Kansas City Power & Light Company, also owns all the outstanding shares of KCPL GMO and its Missouri-based electric utility assets.

Schedule Page: 326.2 Line No.: 4 Column: b

Border customer.

Schedule Page: 326.2 Line No.: 5 Column: a

Great Plains Energy, the parent company of Kansas City Power & Light Company, also owns all the outstanding shares of KCPL GMO and its Missouri-based electric utility assets.

Schedule Page: 326.2 Line No.: 11 Column: a

KCP&L purchases firm capacity and energy from Mid-American Energy Company from June 1, 1996 through May 31, 2010 per the Capacity and Energy Confirmation dated April 13, 2004, to Amendment No. 2 to Confirmation Agreement dated December 15, 2005.

Schedule Page: 326.3 Line No.: 1 Column: a

KCP&L purchases firm capacity and energy from Morgan Stanley Capital Group from June 1, 2001 through May 31, 2011, per the Capacity Agreement dated February 13, 1996.

Schedule Page: 326.3 Line No.: 14 Column: a

Non LF Service - SPS Electric Coordination Service Tariff.

Schedule Page: 326.4 Line No.: 1 Column: a

Non LF Service - SPS Attachment S.

Schedule Page: 326.4 Line No.: 2 Column: a

Non LF Service - Energy from Southwest Power Pool RTO. Market start date February 1, 2007.

Schedule Page: 326.4 Line No.: 13 Column: a

Elimination of activity between KCP&L and KCP&L GMO.

Schedule Page: 326.4 Line No.: 14 Column: a

The generating unit, Iatan 2, was placed in service in August 2010. \$5,223,925 is the fair value of energy delivered to KCP&L's electric system and credited to construction during start up and testing. \$9,329,710 is the Missouri jurisdictional portion of the fair value of energy delivered to KCP&L's system and credited to a regulatory asset.

Schedule Page: 326.5 Line No.: 1 Column: a

Accounting reclass.

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.

2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).

3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)

4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Associated Electric	Kansas City Power & Light	Associated Electric	LFP
2	KCP&L GMOC-MOPUB	Kansas City Power & Light	KCP&L GMOC-MOPUB	OS
3	Ameren	Kansas City Power & Light	Ameren	LFP
4	Westar Energy	Kansas City Power & Light	Westar Energy	LFP
5	Board of Public Utilities	Kansas City Power & Light	Board of Public Utilities	LFP
6	Southwest Power Pool	Kansas City Power & Light	SPP	OS
7	City of Slater	Kansas City Power & Light	City of Slater	FNO
8	City of Prescott	Kansas City Power & Light	City of Prescott	FNO
9	City of Pomona	Kansas City Power & Light	City of Pomona	FNO
10	KEPCO	Kansas City Power & Light	KEPCO	FNO
11	KCP&L GMOC-MOPUB (Bates)	Kansas City Power & Light	KCP&L GMOC-MOPUB	FNO
12	Ameren	Kansas City Power & Light	Ameren	OS
13	City of Independence	Kansas City Power & Light	City of Independence	OS
14	City of Slater	Kansas City Power & Light	City of Slater	AD
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
89	Associated Electric	Dover, Higginsville	3	7,437	7,437	1
58	MPS Interconnects	Multiple				2
104	Ameren	Columbia, Mauer Lake	86	386,513	386,513	3
55	Westar Energy	Kaw Valley Hydro	1	2,829	2,829	4
54	Board of Pub Util	BPU-Hydro	39	81,540	81,540	5
SPP Tariff	Multiple	Multiple				6
128	City of Slater	Norton Substation				7
127	City of Prescott	Centerville Sub				8
126	City of Pomona	South Ottawa Sub				9
130	KEPCO	Multiple				10
129	MPS Interconnects	MPS-Bates				11
104	Ameren	Liberty				12
101	City of Independence	Blue Valley Stm Elec				13
128	City of Slater	Norton Substation				14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			129	478,319	478,319	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions referred to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.

10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.

11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges (\$) (k)	Energy Charges (\$) (l)	(Other Charges) (\$) (m)	Total Revenues (\$) (k+l+m) (n)	Line No.
44,280			44,280	1
		203,065	203,065	2
1,052,640			1,052,640	3
13,031			13,031	4
472,464			472,464	5
		10,220,589	10,220,589	6
		61,676	61,676	7
		6,688	6,688	8
		26,620	26,620	9
		224,398	224,398	10
		11,767	11,767	11
		7,008	7,008	12
		5,100	5,100	13
		1,043	1,043	14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
1,582,415	0	10,767,954	12,350,369	

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or “true-ups” for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
1	Not Applicable				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to-Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Megawatt-hours Received (c)	Megawatt-hours Delivered (d)	Demand Charges (\$) (e)	Energy Charges (\$) (f)	Other Charges (\$) (g)	Total Cost of Transmission (\$) (h)
1	Independence Pwr&Light	OS					161,987	161,987
2	KCP&L GMO-MPS	OS					68,353	68,353
3	Entergy Electric System	NF				279,389		279,389
4	Midwest Indep Sys Oper	NF				241,662		241,662
5	PJM Interconnection LLC	NF				-51		-51
6	Southwest Power Pool	LFP				12,618,596		12,618,596
7	Southwest Power Pool	SFP				748,128		748,128
8	Southwest Power Pool	NF				689,481	6,449	695,930
9	Southwestern Public Svc	LFP					208,332	208,332
10								
11	Accounting adjustment							
12								
13								
14								
15								
16								
	TOTAL					14,577,205	445,121	15,022,326

Name of Respondent Kansas City Power & Light Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Schedule Page: 332 Line No.: 1 Column: a

Facility Use Charge billed to KCP&L from Independence is for capacity on Independence's 161 KV transmission line from KCP&L Blue Mills substation.

Schedule Page: 332 Line No.: 2 Column: a

Emergency and Firm Transmission Service delivered to KCP&L is for transmission capacity needed from KCP&L GMO so that KCP&L can carry its load. There is no actual scheduling of energy as with a usual type of transmission service. Energy purchases are handled through purchased power account 555. Great Plains Energy, the parent company of Kansas City Power & Light Company, also owns all the outstanding shares of KCP&L GMO and its Missouri-based electric utility assets.

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	1,167,679
2	Nuclear Power Research Expenses	1,328,846
3	Other Experimental and General Research Expenses	2,800,309
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	1,261,308
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < \$5,000	
6		
7	Employee Services	
8	Winning Culture	1,216
9	Support Services	24,127
10	Safety/Medical	6,763
11		
12	Maintain Corporate Visibility	
13	Regulatory	
14	Reporting	385,768
15	Compliance	29,309
16	Shareholder Communications	1,140
17	Other (Corp Vis and Company/Divisional Meetings)	157,582
18		
19	Support Industry Programs	
20	Labor	5,529
21		
22	Environmental Expense	
23	Manage Environmental Programs	2,096
24		
25	Other	
26	Other Labor/Transportation	-3,001
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	7,168,671

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of acquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403); (c) Depreciation Expense for Asset Retirement Costs (Account 403.1); (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).

2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.

3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.

Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.

In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.

For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.

4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant				12,255,000	12,255,000
2	Steam Production Plant	61,900,725	950,834	29,891		62,881,450
3	Nuclear Production Plant	23,925,660				23,925,660
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	20,329,663	126,500			20,456,163
7	Transmission Plant	11,121,449			153,689	11,275,138
8	Distribution Plant	46,632,931			210,683	46,843,614
9	Regional Transmission and Market Operation					
10	General Plant	6,883,422		147,214	72,652,888	79,683,524
11	Common Plant-Electric					
12	TOTAL	170,793,850	1,077,334	177,105	85,272,260	257,320,549

B. Basis for Amortization Charges

Basis and effective annual rates used to record Account 405 Amortization:					
	FERC A/C	Nov 2010 Plant Base	Annual Rate Nov 2010	Dec 2010 Plant Base	Annual Rate Effective Dec 2010
Misc Intangible Plant:					
Station Equipment	303	\$ 2,036,014	2.70%	\$ 2,036,014	1.75%
Capitalized Software (5 yr)		\$104,301,128	20.00%	\$103,223,780	20.00%
Capitalized Software (10 yr)		\$ 61,738,736	10.00%	\$ 61,738,741	10.00%
Steam Prod Structures		\$ 36,980	3.86%	\$ 36,980	2.47%
Transmission Line		\$ 5,839,216	3.74%	\$ 2,979,747	2.80%
Other Production Plant	340	\$ 93,269	.64%	\$ 93,269	.64%
Transmission Plant	350	\$ 25,147,441	.63%	\$ 25,147,441	.64%
Distribution Plant	360	\$ 16,589,190	1.27%	\$ 16,589,190	1.27%
Basis used to record Account 404 Amortization:					
Steam Production Structures	311	\$ 272,489	**	\$ 272,489	**
General Structures	390	\$ 30,917,967	**	\$ 30,917,967	**
**Represents multiple leasehold improvements which are being amortized over the remaining life of the applicable leases.					

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	DEPRECIABLE PLANT						
13	AND RATES THROUGH						
14	NOV 2010						
15							
16	303-Misc Intang-Subst	2,036			2.70		
17	303-Cap Soft 5-yr Cust	30,545			20.00		
18	303-Cap Soft 5-yr Ener	8,666			20.00		
19	303-Cap Soft 5-yr PD	16,729			20.00		
20	303-Cap Soft 5-yr S/W	20,766			20.00		
21	303-Cap Soft 5-yr T/D	3,780			20.00		
22	303-Cap Sof 10-yr Cust	39,912			10.00		
23	303-Cap Sof 10-yr Ener	21,827			10.00		
24	303-Cap Soft 5-yr WC	22,738			20.00		
25	303-Steam Prod Struct	35			3.86		
26	303-Trans Line	2,980			3.74		
27	INTANGIBLES TOTAL	170,014			3.81		
28							
29	311 Structures	157,828			3.37		
30	311 Struct Haw 5 Rebl	8,923			0.83		
31	311 Structures Iatan 2	101,533			3.37		
32	312 Boiler Plant	1,041,250			3.86		
33	312 Boil Plt Unit Trns	21,250			4.73		
34	312 Boiler Plant - AQC	34,390			6.59		
35	312 Boil Plt-Haw 5 Rbd	222,423			0.96		
36	312 Boiler Plt Iatan 2	730,742			3.86		
37	314 Turbogenerator	250,495			2.77		
38	314 Turbogntn Iatan 2	100,629			2.77		
39	315 Accessory Equip	120,442			3.04		
40	315 Acc Equip - Haw 5	39,397			0.75		
41	315 Acc Equip - Comput	14			4.32		
42	315 Acc Equip Iatan 2	33,829			3.04		
43	316 Misc Pwr Plt Equip	30,464			3.81		
44	316 Misc Pwr Plt Haw 5	2,305			0.94		
45	316 Misc Pwr Iatan 2	3,781			3.81		
46	321 Nucl Str & Improv	401,605			1.55		
47	321 Nuc S/I MO Gr-up	19,155			1.55		
48	322 Nuc Reactor	528,125			1.73		
49	322 Nuc Reac MO Gr-up	48,354			1.73		
50	323 Nuc Turbine	169,396			1.96		

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	323 Nuc Tur MO Gr-up	5,843			1.96		
13	324 Nuc Accessory	126,272			1.73		
14	324 Nuc Ac MO Gr-up	5,960			1.73		
15	325 Nuc Misc Pwr Pt Eq	71,877			2.36		
16	325 Nuc Pwr MO Gr-up	1,124			2.36		
17	340 Oth Prod Land Rgts	93			0.64		
18	341 Oth Prod Struct	5,291			4.06		
19	341 Oth Prod Str Wind	3,433			5.00		
20	342 Oth Prod Fuel Hldr	11,665			4.06		
21	344 Oth Prod Generator	266,194			4.06		
22	344 Oth Prd Gen Wind	154,283			5.00		
23	345 Oth Prd Acc Equip	21,814			4.06		
24	345 Oth Prd Ac Eq Wind	128			5.00		
25	PRODUCTION TOTAL	4,740,307					
26							
27	350 Land Rgts				0.63		
28	350 Land Rgts MO Situs	11,320			0.63		
29	350 Land Rgts KS Situs	13,828			0.63		
30	350 Land Rgts Wolf Cr				0.63		
31	350 Wolf Cr Gr AFUDC				1.19		
32	352 Struct & Impr	4,553			1.81		
33	352 Wolf Cr Str & Imp	250			1.81		
34	352 Wolf Cr Gr AFUDC	16			1.36		
35	353 Station Equip	131,013			2.70		
36	353 Wolf Cr Station Eq	9,007			2.70		
37	353 Wolf Cr Gr AFUDC	557			2.24		
38	353 Station Eq Comm Eq	7,746			3.03		
39	354 Towers & Fixtures	4,288			2.35		
40	355 Poles & Fixtures				3.74		
41	355 Pol & Fix MO Situs	59,892			3.74		
42	355 Pol & Fix KS Situs	52,366			3.74		
43	355 Wolf Cr Pol & Fix	58			3.74		
44	355 Wolf Cr Gr AFUDC	4			3.59		
45	356 OH Conduc & Device				3.12		
46	356 OH Con/Dev MO Situ	39,236			3.12		
47	356 OH Con/Dev KS Situ	60,200			3.12		
48	356 Wolf Cr OH Con Dev	39			3.12		
49	356 Wolf Cr Gr AFUDC	3			3.10		
50	357 Undergrd Circuit	3,539			1.68		

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	358 Undergrd Cond Dev	2,900			2.20		
13	TRANSMISSION TOTAL	400,815					
14							
15	360 Dist Land Rgts	16,589			1.27		
16	361 Dist Str & Impr	11,324			2.65		
17	362 Dist Station Equip	169,294			2.21		
18	362 Dis Stn Eq Comm Eq	4,131			3.06		
19	364 Dist Pol Twr & Fix	251,979			3.83		
20	365 Dis OH Conductor	202,616			2.37		
21	366 Dis UG Circuit	219,192			1.68		
22	367 Dis UG Con & Dev	406,458			2.22		
23	368 Dis Line Transform	245,091			3.31		
24	369 Dist Services	93,697			3.01		
25	370 Dist Meters	89,448			3.89		
26	371 Dist Cust Prem Ins	11,775			10.09		
27	373 Dist Str Ltg & Tra	36,017			3.37		
28	DISTRIBUTION TOTAL	1,757,611					
29							
30	390 Struc & Improv	62,597			2.25		
31	391 Off Fur & Equip	10,365			4.33		
32	391 Of Fur & Eq WC 706	3,484			4.33		
33	391 Of Fur & Eq Comp	1,473			4.33		
34	392 Transp Eq	40,909			6.51		
35	393 Stores Equip	959			3.39		
36	394 Tools, Shop Equip	4,270			3.03		
37	395 Laboratory Equip	5,908			3.14		
38	396 Power Oper Eq	23,129			5.45		
39	397 Communic Eq	101,487			3.04		
40	397 Wolf Cr Comm Eq	143			3.04		
41	397 Wolf Cr Gr AFUDC	9			2.50		
42	398 Misc Equip	491			4.28		
43	GENERAL PLANT TOTAL	255,224					
44							
45	Per Docket No.						
46	ER10-230-000: See Note						
47	1 & 2 in footnote						
48							
49							
50							

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	DEPRECIABLE PLANT						
13	RATES EFF. DEC 2010						
14							
15	303-Misc Intang-Subst	2,036			1.75		
16	303-Cap Soft 5-yr Cust	30,933			20.00		
17	303-Cap Soft 5-yr Ener	8,776			20.00		
18	303-Cap Soft 5-yr PD	16,942			20.00		
19	303-Cap Soft 5-yr S/W	21,031			20.00		
20	303-Cap Soft 5-yr T/D	3,828			20.00		
21	303-Cap Sof 10-yr Cust	39,912			10.00		
22	303-Cap Sof 10-yr Ener	21,827			10.00		
23	303-Cap Soft 5-yr WC	22,791			20.00		
24	303-Steam Prod Struct	35			2.47		
25	303-Trans Line	5,839			2.80		
26	INTANGIBLES TOTAL	173,950					
27							
28	311 Structures	159,394			2.56		
29	311 Struct Haw 5 Rebl	8,923			0.70		
30	311 Structures Iatan 2	102,456			2.60		
31	312 Boiler Plant 312	1,040,782			2.47		
32	312 Boil Plt Unit Trns	21,250			3.31		
33	312 Boiler Plant - AQC	34,466			2.00		
34	312 Boil Plt-Haw 5 Rbd	222,423			0.83		
35	312 Boiler Plt Iatan 2	724,422			2.94		
36	314 Turbogenerator	250,784			3.20		
37	314 Turbognt Iatan 2	101,958			2.59		
38	315 Accessory Equip	123,089			3.50		
39	315 Asc Equip - Haw 5	39,397			0.80		
40	315 Acc Equip - Comput	14			4.66		
41	315 Acc Equip Iatan 2	34,310			2.79		
42	316 Misc Pwr Plt Equip	30,760			2.72		
43	316 Misc Pwr Plt Haw 5	2,305			0.75		
44	316 Misc Pwr Iatan 2	3,914			2.82		
45	321 Nucl Str & Improv	401,724			1.49		
46	321 Nuc S/I MO Gr-up	19,155			1.55		
47	322 Nuc Reactor	528,152			1.73		
48	322 Nuc Reac MO Gr-up	48,354			1.73		
49	323 Nuc Turbine	169,397			1.82		
50	323 Nuc Tur MO Gr-up	5,843			1.96		

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	324 Nuc Accessory	126,272			1.93		
13	324 Nuc Ac MO Gr-up	5,960			1.73		
14	325 Nuc Misc Pwr Pt Eq	77,553			2.64		
15	325 Nuc Misc MO Gr-up	1,124			2.36		
16	340 Oth Prod Land Rgts	93			0.64		
17	341 Oth Prod Struct	5,291			3.27		
18	341 Oth Prod Str Wind	3,433			5.06		
19	342 Oth Prod Fuel Hldr	11,665			3.33		
20	344 Oth Prod Generator	266,083			3.56		
21	344 Oth Prd Gen Wind	252,057			4.81		
22	345 Oth Prd Acc Equip	21,823			3.03		
23	345 Oth Prd Ac Eq Wind	128			5.21		
24	PRODUCTION TOTAL	4,844,754					
25							
26	350 Land Rights				0.64		
27	350 Land Rgts MO Situs	11,320			0.64		
28	350 Land Rgts KS Situs	13,827			0.64		
29	350 Land Rgts Wolf Cr				0.64		
30	350 Wolf Cr Gr AFUDC				1.19		
31	352 Struct & Impr	4,556			1.39		
32	352 Wolf Cr Str & Imp	250			1.39		
33	352 Wolf Cr Gr AFUDC	16			1.36		
34	353 Station Equip	136,493			1.75		
35	353 Wolf Cr Station Eq	9,007			1.75		
36	353 Wolf Cr Gr AFUDC	557			2.24		
37	353 Station Eq Comm Eq	7,829			12.40		
38	354 Towers & Fixtures	4,288			1.29		
39	355 Poles & Fixtures				2.80		
40	355 Pol & Fix MO Situs	59,592			2.80		
41	355 Pol & Fix KS Situs	52,105			2.80		
42	355 Wolf Cr Pol & Fix	58			2.80		
43	355 Wolf Cr Gr AFUDC	4			3.59		
44	356 OH Conduc & Device				1.69		
45	356 OH Con/Dev MO Situ	38,880			1.69		
46	356 OH Con/Dev KS Situ	59,653			1.69		
47	356 Wolf Cr OH Con Dev	39			1.69		
48	356 Wolf Cr Gr AFUDC	3			3.10		
49	357 Undergrd Circuit	3,539			1.09		
50	358 Undergrd Cond Dev	2,900			2.29		

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	TRANSMISSION TOTAL	404,916					
13							
14	360 Dist Land Rgts	16,589			1.27		
15	361 Dist Str & Impr	11,324			2.42		
16	362 Dist Station Equip	168,377			1.85		
17	362 Dis Stn Eq Comm Eq	4,093			11.25		
18	364 Dist Pol Twr & Fix	252,206			3.37		
19	365 Dis OH Conductor	203,226			2.13		
20	366 Dis UG Circuit	220,887			1.08		
21	367 Dis UG Con & Dev	405,943			1.11		
22	368 Dis Line Transform	246,706			2.41		
23	369 Dist Services	93,872			4.14		
24	370 Dist Meters	92,228			3.20		
25	371 Dist Cust Prm Ins	11,896			6.78		
26	373 Dist Str Ltg & Tra	36,506			4.65		
27	DISTRIBUTION TOTAL	1,763,853					
28							
29	390 Struc & Improv	66,949			2.60		
30	391 Off Fur & Equip	10,366			5.03		
31	391 Of Fur & Eq WC	3,597			5.21		
32	391 Of Fur & Eq Comp	2,160			8.41		
33	392 Trans Eq Autos	1,616			5.42		
34	392 Trans Eq Lt Trucks	8,409			6.93		
35	392 Trans Eq Hvy Truck	28,583			6.21		
36	392 Trans Eq Tractors	685			5.39		
37	392 Trans Eq Trailers	1,822			3.53		
38	393 Stores Equip	959			3.27		
39	394 Tools, Shop Equip	4,288			2.95		
40	395 Laboratory Equip	6,067			3.73		
41	396 Power Oper Equip	23,544			6.29		
42	397 Communication Equip	102,693			3.66		
43	397 Wolf Cr Comm Equip	143			3.66		
44	397 Wolf Cr Gr AFUDC	9			2.50		
45	398 Misc Equip	493			3.69		
46	GENERAL PLANT TOTAL	262,383					
47							
48	Per Docket No.						
49	ER10-230-000: See Note						
50	1 & 2 in footnote						

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report 2010/Q4
Kansas City Power & Light Company			
FOOTNOTE DATA			

Schedule Page: 336 Line No.: 1 Column:

Per Kansas Rate Order-KCPL Docket No. 10-KCPE-415-RTS, the Kansas Corporation Commission authorized new depreciation rates effective December 1, 2010.

Schedule Page: 336.2 Line No.: 45 Column: a

This footnote provides additional details for use in the FERC transmission formula rate, Docket No. ER10-230-000.

**Kansas City Power & Light Co.
Jurisdictional Allocation Factors Through November 2010**

LN	A/C	Description	Allocation Basis	Missouri Allocation Factor	Kansas Allocation Factor	FERC Allocation Factor	KCPL Composite Total Allocation Factor
1	301	Organization	PTD	54.1128%	45.5559%	0.3313%	100.00%
2	302	Franchises	100 MO	100.0000%	0.0000%	0.0000%	100.00%
3	303	Misc Intangible - Substation (like A/C 353)	D	53.5548%	45.8257%	0.6196%	100.00%
4	303	Misc Intangible - Cap Software 5 Year (Customer)	C2	53.2989%	46.6997%	0.0000%	100.00%
5	303	Misc Intangible - Cap Software 5 Year (Energy)	E1	57.0092%	42.3695%	0.6213%	100.00%
6	303	Misc Intangible - Cap Software 5 Year (Prod Demand)	D	53.5548%	45.8257%	0.6196%	100.00%
7	303	Misc Intangible - Cap Software 5 Year (Sal/Wages)	SW	53.9402%	45.5864%	0.4735%	100.00%
8	303	Misc Intangible - Cap Software 5 Year (Transm Demand)	D	53.5548%	45.8257%	0.6196%	100.00%
9	303	Misc Intangible - Cap Software 10 Year (Customer)	C2	53.2989%	46.6997%	0.0000%	100.00%
10	303	Misc Intangible - Cap Software 10 Year (Energy)	E1	57.0092%	42.3695%	0.6213%	100.00%
11	303	Misc Intangible - Commun Equip (like A/C 397)	T&D	54.1128%	45.5559%	0.3313%	100.00%
12	303	Misc Intangible - Assec Eq (like A/C 345)	D	54.1128%	45.5559%	0.3313%	100.00%
13	303	Misc Intangible - Steam Prod Structures (like A/C 312)	S	53.5548%	45.8257%	0.6196%	100.00%
14	303	Misc Intangible - Trans Line (like A/C 355)	PP	50.3622%	49.1065%	0.5313%	100.00%
15	350	Land	N/A	53.5548%	45.8257%	0.6196%	100.00%
16	350	Land Rights	PP	52.6648%	46.7357%	0.5995%	100.00%
17	350	Land Rights - MO Situs	100MO	100.0000%	0.0000%	0.0000%	100.00%
18	350	Land Rights - KS Situs	100KS	0.0000%	100.0000%	0.0000%	100.00%
19	350	Land Rights - Wolf Creek	PP	52.6648%	46.7357%	0.5995%	100.00%
20	350	Wolf Creek Gross AFUDC - Land Rights	100MO	100.0000%	0.0000%	0.0000%	100.00%
21	352	Structures and Improvements	PP	53.5548%	45.8257%	0.6196%	100.00%
22	352	Wolf Creek - Structures and Improvement	PP	53.5548%	45.8257%	0.6196%	100.00%
23	352	Wolf Creek Gross AFUDC - Structures	100MO	100.0000%	0.0000%	0.0000%	100.00%
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Name of Respondent	This Report is:	Date of Report	Year/Period of Report		
Kansas City Power & Light Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 04/15/2011	2010/Q4		
FOOTNOTE DATA					
& Improvement					
24 353 Station Equipment	PP	53.5548%	45.8257%	0.6196%	100.00%
25 353 Wolf Creek - Station Equipment	PP	53.5548%	45.8257%	0.6196%	100.00%
26 353 Wolf Creek Gross AFUDC - Station Equipment	100MO	100.0000%	0.0000%	0.0000%	100.00%
27 353 Station Equipment- Communication Eq (same as 397)	PP	53.5548%	45.8257%	0.6196%	100.00%
28 354 Towers and Fixtures	PP	53.5548%	45.8257%	0.6196%	100.00%
29 355 Poles and Fixtures	PP	50.3622%	49.1065%	0.5313%	100.00%
30 355 Poles and Fixtures - MO Situs	100MO	100.0000%	0.0000%	0.0000%	100.00%
31 355 Poles and Fixtures - KS Situs	100KS	0.0000%	100.0000%	0.0000%	100.00%
32 355 Wolf Creek - Poles and Fixtures	PP	50.3622%	49.1065%	0.5313%	100.00%
33 355 Wolf Creek Gross AFUDC - Poles and Fixtures	100MO	100.0000%	0.0000%	0.0000%	100.00%
34 356 Overhead Conductors and Devices	PP	50.2742%	49.1944%	0.5314%	100.00%
35 356 Overhead Conductors and Devices - MO Situs	100MO	100.0000%	0.0000%	0.0000%	100.00%
36 356 Overhead Conductors and Devices - KS Situs	100KS	0.0000%	100.0000%	0.0000%	100.00%
37 356 Wolf Creek - Overhead Conductors and Devices	PP	50.2742%	49.1944%	0.5314%	100.00%
38 356 Wolf Creek Gross AFUDC - O/H Conductor & Devices	100MO	100.0000%	0.0000%	0.0000%	100.00%
39 357 Underground Conduit	PP	53.5548%	45.8257%	0.6196%	100.00%
40 358 Underground Conductors and Devices	PP	53.5548%	45.8257%	0.6196%	100.00%
41 389 Land and Land Rights	PTD	53.9653%	45.6211%	0.4136%	100.00%
42 390 Structures and Improvements	PTD	53.9653%	45.6211%	0.4136%	100.00%
43 390 Structures and Impr - Leasehold Impr (amort over lease)	PTD	53.9653%	45.6211%	0.4136%	100.00%
44 391 Office Furniture and Equipment	PTD	53.9653%	45.6211%	0.4136%	100.00%
45 391 Office Furniture and Equipment - WC Sub 706	PTD	53.9653%	45.6211%	0.4136%	100.00%
46 391 Office Furniture and Equipment - Computers	PTD	53.9653%	45.6211%	0.4136%	100.00%
47 392 Transportation Equipment	T&D	52.9669%	46.9216%	0.1115%	100.00%
48 393 Stores Equipment	PTD	53.9653%	45.6211%	0.4136%	100.00%
49 394 Tools, Shop and Garage Equipment	PTD	53.9653%	45.6211%	0.4136%	100.00%
50 395 Laboratory Equipment	PTD	53.9653%	45.6211%	0.4136%	100.00%
51 396 Power Operated Equipment	T&D	52.9669%	46.9216%	0.1115%	100.00%
52 397 Communication Equipment	T&D	52.9669%	46.9216%	0.1115%	100.00%
53 397 Wolf Creek - Communication Equipment	T&D	52.9669%	46.9216%	0.1115%	100.00%
54 397 Wolf Creek Gross AFUDC - Communication Equip.	100MO	100.0000%	0.0000%	0.0000%	100.00%
55 398 Miscellaneous Equipment	PTD	53.9653%	45.6211%	0.4136%	100.00%
56 399 Other Tangible Property	100MO	100.0000%	0.0000%	0.0000%	100.00%
57 399 Other Tangible Property	100KS	0.0000%	100.0000%	0.0000%	100.00%

Notes:

- 1 KCP&L adopted a composite depreciation calculation in FY 2010 based on allocation methods of the predominant regulatory jurisdiction applied to the approved depreciation rates for each jurisdiction. Missouri is the predominant jurisdiction for KCP&L based upon size of load. Although the specific weighting values will change from year to year, the allocation methods documented in the above table will not change without

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report 2010/Q4
Kansas City Power & Light Company			
FOOTNOTE DATA			

an order from the Commission approving the new methods or depreciation rates. As the formula rate is updated each year, the above table will be populated with allocation factors reflecting the approved methods in order to calculate a composite depreciation rate for each line.

2 The Allocation Basis codes in the above table represent the weighting methods to apply to the approved jurisdictional depreciation rates to calculate composite depreciation expense on an account-specific basis for FERC Form No. 1. Following is the definition of each code:

C2 - The customer allocator is based on the number of customers receiving power in each regulatory jurisdiction.

D - The demand allocator is based on the monthly coincident peak (CP) demands for each jurisdiction.

E1 - The energy allocator is based on the total annual kilowatt-hour usage of each jurisdiction's customers, adjusted for line losses.

PP - The PP allocator reflects the total production plant value allocated and specifically assigned to each jurisdiction as a percentage of KCP&L total production plant.

PTD - The PTD allocator reflects the total production, transmission, and distribution plant value allocated and specifically assigned to each jurisdiction as a percentage of KCP&L total production, transmission, and distribution plant.

T&D - The T&D allocator reflects the total transmission and distribution plant value allocated and specifically assigned to each jurisdiction as a percentage of KCP&L total transmission and distribution plant.

S - The steam plant allocator is a blend of the demand allocator (D) and the energy allocator (E1), based on the percentage of production plant devoted to non-environmental and environmental functions, respectively.

SW - The salary and wages allocator represents the weighting of salary and wages (excluding Administrative and General) for production, transmission, distribution, and customer accounts.

3 Allocation factors based on 2008 Missouri Surveillance Reporting.

Schedule Page: 336.5 Line No.: 48 Column: a

This footnote provides additional details for use in the FERC transmission formula rate, Docket No. ER10-230-000.

**Kansas City Power & Light Co.
Jurisdictional Allocation Factors Effective December 1, 2010**

<u>LN</u>	<u>A/C</u>	<u>Description</u>	<u>Allocation Basis</u>	<u>Missouri Allocation Factor</u>	<u>Kansas Allocation Factor</u>	<u>FERC Allocation Factor</u>	<u>KCPL Composite Total Allocation Factor</u>
1	301	Organization	PTD	53.8416%	45.8280%	0.3304%	100.00%
2	302	Franchises	100 MO	100.0000%	0.0000%	0.0000%	100.00%
3	303	Misc Intangible - Substation (like A/C 353)	D	53.5050%	45.8815%	0.6135%	100.00%
4	303	Misc Intangible - Cap Software 5 Year (Customer)	C2	53.1977%	46.8009%	0.0000%	100.00%
5	303	Misc Intangible - Cap Software 5 Year (Energy)	E1	57.0724%	42.2497%	0.6779%	100.00%
6	303	Misc Intangible - Cap Software 5 Year	D	53.5050%	45.8815%	0.6135%	100.00%
FERC FORM NO. 1 (ED. 12-87)			Page	450.3			

Name of Respondent	This Report is:	Date of Report	Year/Period of Report		
Kansas City Power & Light Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 04/15/2011	2010/Q4		
FOOTNOTE DATA					
7 303 (Prod Demand) Misc Intangible - Cap Software 5 Year (Sal/Wages)	SW	53.3307%	46.2024%	0.4670%	100.00%
8 303 Misc Intangible - Cap Software 5 Year (Transm Demand)	D	53.5050%	45.8815%	0.6135%	100.00%
9 303 Misc Intangible - Cap Software 10 Year (Customer)	C2	53.1977%	46.8009%	0.0000%	100.00%
10 303 Misc Intangible - Cap Software 10 Year (Energy)	E1	57.0724%	42.2497%	0.6779%	100.00%
11 303 Misc Intangible - Commun Equip (like A/C 397)	T&D	53.8416%	45.8280%	0.3304%	100.00%
12 303 Misc Intangible - Assec Eq (like A/C 345)	D	53.8416%	45.8280%	0.3304%	100.00%
13 303 Misc Intangible - Steam Prod Structures (like A/C 312)	S	53.5050%	45.8815%	0.6135%	100.00%
14 303 Misc Intangible - Trans Line (like A/C 355)	PP	49.6097%	49.9028%	0.4875%	100.00%
15 350 Land	N/A	53.5050%	45.8815%	0.6135%	100.00%
16 350 Land Rights	PP	53.5050%	45.8815%	0.6135%	100.00%
17 350 Land Rights - MO Situs	100MO	100.0000%	0.0000%	0.0000%	100.00%
18 350 Land Rights - KS Situs	100KS	0.0000%	100.0000%	0.0000%	100.00%
19 350 Land Rights - Wolf Creek	PP	53.5050%	45.8815%	0.6135%	100.00%
20 350 Wolf Creek Gross AFUDC - Land Rights	100MO	100.0000%	0.0000%	0.0000%	100.00%
21 352 Structures and Improvements	PP	53.5050%	45.8815%	0.6135%	100.00%
22 352 Wolf Creek - Structures and Improvement	PP	53.5050%	45.8815%	0.6135%	100.00%
23 352 Wolf Creek Gross AFUDC - Structures & Improvement	100MO	100.0000%	0.0000%	0.0000%	100.00%
24 353 Station Equipment	PP	53.5050%	45.8815%	0.6135%	100.00%
25 353 Wolf Creek - Station Equipment	PP	53.5050%	45.8815%	0.6135%	100.00%
26 353 Wolf Creek Gross AFUDC - Station Equipment	100MO	100.0000%	0.0000%	0.0000%	100.00%
27 353 Station Equipment- Communication Eq (same as 397)	PP	53.5050%	45.8815%	0.6135%	100.00%
28 354 Towers and Fixtures	PP	53.6238%	45.7642%	0.6120%	100.00%
29 355 Poles and Fixtures	PP	49.6097%	49.9028%	0.4875%	100.00%
30 355 Poles and Fixtures - MO Situs	100MO	100.0000%	0.0000%	0.0000%	100.00%
31 355 Poles and Fixtures - KS Situs	100KS	0.0000%	100.0000%	0.0000%	100.00%
32 355 Wolf Creek - Poles and Fixtures	PP	49.6097%	49.9028%	0.4875%	100.00%
33 355 Wolf Creek Gross AFUDC - Poles and Fixtures	100MO	100.0000%	0.0000%	0.0000%	100.00%
34 356 Overhead Conductors and Devices	PP	49.0102%	50.5027%	0.4871%	100.00%
35 356 Overhead Conductors and Devices - MO Situs	100MO	100.0000%	0.0000%	0.0000%	100.00%
36 356 Overhead Conductors and Devices - KS Situs	100KS	0.0000%	100.0000%	0.0000%	100.00%
37 356 Wolf Creek - Overhead Conductors and Devices	PP	49.0102%	50.5027%	0.4871%	100.00%
38 356 Wolf Creek Gross AFUDC - O/H Conductor & Devices	100MO	100.0000%	0.0000%	0.0000%	100.00%
39 357 Underground Conduit	PP	50.9768%	48.4387%	0.5845%	100.00%
40 358 Underground Conductors and Devices	PP	52.0807%	47.3220%	0.5972%	100.00%
41 389 Land and Land Rights	PTD	53.9812%	45.5997%	0.4191%	100.00%

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kansas City Power & Light Company		04/15/2011	2010/Q4

FOOTNOTE DATA

42	390 Structures and Improvements	PTD	53.9812%	45.5997%	0.4191%	100.00%
43	390 Structures and Impr - Leasehold Impr (amort over lease)	PTD	53.9812%	45.5997%	0.4191%	100.00%
44	391 Office Furniture and Equipment	PTD	53.9812%	45.5997%	0.4191%	100.00%
45	391 Office Furniture and Equipment - WC Sub 706	PTD	53.9812%	45.5997%	0.4191%	100.00%
46	391 Office Furniture and Equipment - Computers	PTD	53.9812%	45.5997%	0.4191%	100.00%
47	392 Transportation Equipment	T&D	53.2170%	46.6903%	0.0927%	100.00%
48	393 Stores Equipment	PTD	53.9812%	45.5997%	0.4191%	100.00%
49	394 Tools, Shop and Garage Equipment	PTD	53.9812%	45.5997%	0.4191%	100.00%
50	395 Laboratory Equipment	PTD	53.9812%	45.5997%	0.4191%	100.00%
51	396 Power Operated Equipment	T&D	53.2170%	46.6903%	0.0927%	100.00%
52	397 Communication Equipment	T&D	53.2170%	46.6903%	0.0927%	100.00%
53	397 Wolf Creek - Communication Equipment	T&D	53.2170%	46.6903%	0.0927%	100.00%
54	397 Wolf Creek Gross AFUDC - Communication Equip.	100MO	100.0000%	0.0000%	0.0000%	100.00%
55	398 Miscellaneous Equipment	PTD	53.9812%	45.5997%	0.4191%	100.00%
56	399 Other Tangible Property	100MO	100.0000%	0.0000%	0.0000%	100.00%
57	399 Other Tangible Property	100KS	0.0000%	100.0000%	0.0000%	100.00%

Notes:

- KCP&L adopted a composite depreciation calculation in FY 2010 based on allocation methods of the predominant regulatory jurisdiction applied to the approved depreciation rates for each jurisdiction. Missouri is the predominant jurisdiction for KCP&L based upon size of load. Although the specific weighting values will change from year to year, the allocation methods documented in the above table will not change without an order from the Commission approving the new methods or depreciation rates. As the formula rate is updated each year, the above table will be populated with allocation factors reflecting the approved methods in order to calculate a composite depreciation rate for each line.
- The Allocation Basis codes in the above table represent the weighting methods to apply to the approved jurisdictional depreciation rates to calculate composite depreciation expense on an account-specific basis for FERC Form No. 1. Following is the definition of each code:
 - C2 - The customer allocator is based on the number of customers receiving power in each regulatory jurisdiction.
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 - E1 - The energy allocator is based on the total annual kilowatt-hour usage of each jurisdiction's customers, adjusted for line losses.
 - PP - The PP allocator reflects the total production plant value allocated and specifically assigned to each jurisdiction as a percentage of KCP&L total production plant.
 - PTD - The PTD allocator reflects the total production, transmission, and distribution plant value allocated and specifically assigned to each jurisdiction as a percentage of KCP&L total production, transmission, and distribution plant.
 - T&D - The T&D allocator reflects the total transmission and distribution plant value allocated and specifically assigned to each jurisdiction as a percentage of KCP&L total transmission and distribution plant.
 - S - The steam plant allocator is a blend of the demand allocator (D) and the energy allocator (E1), based on the percentage of production plant devoted to non-environmental and environmental functions, respectively.
 - SW - The salary and wages allocator represents the weighting of salary and wages (excluding Administrative and General) for production, transmission, distribution, and customer accounts.

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Kansas City Power & Light Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 04/15/2011	2010/Q4
FOOTNOTE DATA			

- 3 Allocation factors based on 2009 Missouri Surveillance Reporting.
- 4 Per Kansas Rate Order-KCPL Docket No. 10-KCPE-415-RTS, the Kansas Corporation Commission authorized new depreciaton rates effective December 1, 2010.

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
 2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Federal Energy Regulatory Commission		1,194,983	1,194,983	
2					
3	FERC Regulatory Proceedings:				
4	AD10-14 (KCPL comments 07-06-10 rel stds conf)				
5	AD11-1 (KCPL comments 11-18-10 rel stds conf)				
6	ER99-1005 (KCPL Market-Based Rate Authority)				
7	ER09-1306 (KCPL Facilities Use Agrmnt enXco)				
8	ER09-1669 (KCPL/enXco Spearville Joint Agmnt)				
9	ER09-1670 (KCPL/enXco Spearville Joint Agmnt)				
10	ER10-230 (KCPL revsd tariff sheets for OATT)				
11	ER10-334 (SPP/KMEA/KCPL Network Op Agmnt)				
12	ER10-337 (KCPL Ntwrk Integration Trns Svc SPP)				
13	ER10-556 (KCPL Facilities Use Agrmnt enXco)				
14	ER10-739 (KCPL/SPP Large Gen Interconn Agmt)				
15	ER10-833 (KCPL Intervn SPP docket)				
16	ER10-979 (KCPL/SPP Resale/Reassign trns srvc)				
17	ER10-1069 (KCPL Intervn SPP Hwy/Byway docket)				
18	ER10-1269 (KCPL Intervn SPP OATT docket)				
19	ER10-1667 (KCPL/SPP Firm pt to pt trans srvc)				
20	ER10-1684 (KCPL/SPP srvc agmt netwrk integrtn)				
21	ER10-1960 (SPP/KCPL/Others eTariff OATT filng)				
22	ER10-2035 (KCPL 1st rvsd rate sch FERC No 129)				
23	ER10-2074 (KCPL mkt-based baseline eTariff)				
24	ER10-2076 (KCPL OATT baseline filing)				
25	ER10-2429 (KCPL/SPP/KMEA srvc agmt)				
26	ER11-10 KCPL/SPP Firm pt to pt trns srvc agmt)				
27	ER11-2147 (KCPL/Spp Large Genr Interconn Agmt)				
28	ER11-2275 (KCPL Intervn MISO revisns to OATT)				
29	PA11-17 (KCPL short term debt FERC audit)				
30	ES10-58 (KCPL Issue Short-Term Debt)				
31	RM06-16 (KCPL cmmts re: 09-23-10 tech conf)				
32	RM09-25 (KCPL cmmts re: System Prsnl Train Std)				
33	RM10-6 (KCPL cmmts re: NERC Std TPL-002-0)				
34	RM10-23 (KCPL cmmts re: trns Planning & cost)				
35	RM99-9 (Corporate Officials Designation)				
36	RM94-14 (KCPL 2009 Nuclear Decom Trst Fnd Rpt)				
37	RR10-1 (KCPL cmmts re: NERC CIP Stds)				
38	ID-5799 (GPE_KCPL_KCPL GMO FERC Form No. 561)				
39	ZZ10-1 (KCPL CPA Cert Stmt 2009 FERC Form 1)				
40	RM07-10 (Grt Plns Enrgy Svcs Inc Form No. 552)				
41	IN79-6 (KCPL FERC Form No. 580)				
42	Great Plains Energy Services Inc. Form No. 60				
43	KCPL FERC Form No. 714				
44	KCPL FERC Form No. 715				
45	KCPL FERC Form No. 3-Q				
46	TOTAL	1,897,956	8,885,405	10,783,361	7,364,021

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	KCPL FERC Form No. 1				
2	Total FERC Regulatory Proceedings		581,579	581,579	
3					
4	Missouri Public Service Commission				
5	Annual Assessments	955,808		955,808	
6					
7	Missouri Regulatory Proceedings:				
8	Load Research Program		34,677	34,677	
9	Other Regulatory Proceedings:				
10	AX-2008-0201 (Standards of Conduct Rulemaking)				
11	EC-2009-0430 (MPSC Staff Complaint re bus nme)				
12	EC-2010-0184 (KCPL Customer Complaint)				
13	EE-2008-0034 (KCPL 2008 IRP)				
14	EE-2011-0032 (KCPL 2011 IRP)				
15	EE-2011-0119 (KCPL Slr Renewable Enrgy Credits)				
16	EF-2004-0512 (KCPL EIRR Auth Rev Ref Bond App)				
17	EF-2010-0178 (KCPL APP Issue Debt Securities)				
18	EO-2004-0590 (KCPL Wolf Crk Decom Trust Rptg)				
19	EO-2008-0224 (KCPL Wind Investments)				
20	EO-2010-0259 (KCPL Iatan Const Prudence Audit)				
21	EO-2010-0266 (KCPL Vegetation Mgmt Guidelines)				
22	EO-2010-0306 (KCPL 2009 Reliability Indices)				
23	EO-2010-0353 (KCPL Sale of Assets Spearville)				
24	EO-2011-0001 (KCPL Infrastrct Stds Compl Plan)				
25	EO-2011-0088 (SmartGrid eqmt encumbrance)				
26	EO-2011-0090 (KCPL Clean Cities eqmt encmbrnc)				
27	EO-2011-0134 (KCPL SPP cost overruns investig)				
28	ER-2009-0089 (KCPL 2008 Rate Case Application)				
29	ER-2010-0036 (Intrvne AmerenUE 2010 Rate Case)				
30	ER-2010-0130 (Empire District 2010 Rate Case)				
31	ER-2010-0355 (KCPL 2010 Rate Case)				
32	ER-2011-0004 (Intrvne Empire Dist 2011 Rte Cs)				
33	ES-2010-0009 (KCPL 2/4/2009 Iatan Incident)				
34	EU-2010-0194 (KCPL Solar Photovoltaic Reb Prg)				
35	EW-2009-0290 (PURPA IRP)				
36	EW-2009-0291 (PURPA Rate Design)				
37	EW-2009-0292 (PURPA Smart Grid)				
38	EW-2009-0412 (Ch 22 Elec Utility Res Planning)				
39	EW-2010-0187 (Coord st/fed pol dmnd side svgs)				
40	EW-2010-0265 (Impl S.393.1075 MO Enrgy Eff)				
41	EW-2011-0136 (Rep file MO DSM Potential Study)				
42	EX-2010-0122 (Rulemaking-amend reptg reqrmnts)				
43	EX-2010-0169 (Rulemaking-Renewable Energy Std)				
44	EX-2010-0368 (Impl S.393.1075 MO Enrgy Eff)				
45	GW-2010-0120 (Rep-Undrgrnd Facility Dmg Prvtn)				
46	TOTAL	1,897,956	8,885,405	10,783,361	7,364,021

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
 2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	JE-2010-0402 (KCPL TAR AAO Prop C Incr Costs)				
2	JE-2010-0403 (KCPL TAR AAO Prop C Incr Costs)				
3	JE-2010-0430 (KCPL TAR AAO Prop C Incr Costs)				
4	JE-2011-0333 (KCPL TAR Private Area Lighting)				
5	JE-2011-0318 (KCPL TAR Home Perf Energy Star)				
6	JE-2011-0317 (KCPL TAR Energy Eff Education)				
7	JE-2011-0129 (KCPL TAR Lghtng the SmrtGrd Prg)				
8	JE-2011-0113 (KCPL TAR Solr Photovlt Reb Prgm)				
9	JE-2011-0112 (KCPL TAR Enrgy Mgmt Web Prtl Pr)				
10	JE-2011-0110 (KCPL TAR Progm Thrm Pilot Prgm)				
11	JE-2011-0109 (KCPL TAR In Home Dsplay Plt Prg)				
12	JE-2011-0038 (KCPL TAR Enrgy Str New Hms Schd)				
13	JE-2010-0706 (KCPL TAR Avoided Fuel Cost Net)				
14	JE-2010-0692 (KCPL GMO TAR Rate Relief CEP)				
15	JE-2010-0430 (KCPL Acctg Order re RES/Slr reb)				
16	JE-2010-0403 (KCPL Withdrwl Net Metering trff)				
17	JE-2010-0402 (KCPL Withdrwl Net Metering trff)				
18	Total Other Missouri Regulatory Proceedings		1,084,276	1,084,276	
19					
20	Missouri 2009 Rate Case				
21	Amortize 9/2009 - 8/2011		522,995	522,995	871,659
22					
23	Missouri 2010 Rate Case				1,853,944
24					
25	Kansas Corporation Commission				
26	Commission Assessments	850,021		850,021	
27	Citizens Utility Ratepayers Board Assessments	92,127		92,127	
28					
29	Kansas Regulatory Proceedings:				
30	97-GIME-483-GIE (Snow Storm Outages)				
31	02-GIME-365-GIE (Svc Quality for Elec Utility)				
32	06-GIMX-181-GIV (Ring-Fencing Rules)				
33	07-GIMX-446-GIV (Customer Security Deposits)				
34	07-GIMX-1041-GIV (GI - Pension and Retr Costs)				
35	08-GIMX-1142-GIV (GI - Depreciation Issues)				
36	09-GIMX-160-GIV (GI - Incent for Fuel Switch)				
37	10-GIME-215-GIE (Wolf Creek Decom Cost Study)				
38	10-GIMX-013-GIV (GI - RFP for EE Providers)				
39	01-KCPE-708-MIS (GOE Reorganization)				
40	04-KCPE-1025-GIE (KCPL Regulatory Plan)				
41	07-KCPE-1064-ACQ (KCPL/Aquila Merger Authoriz)				
42	08-KCPE-677-CPL (KCPL Rpt ECA Facts in '07 Cs)				
43	10-KCPE-319-COM (KCPL Customer Complaint)				
44	10-KCPE-415-RTS (KCPL 2010 Rate Case)				
45	10-KCPE-422-TAR (KCPL ECA Qtrly Complnce Rpts)				
46	TOTAL	1,897,956	8,885,405	10,783,361	7,364,021

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	10-KCPE-820-COM (KCPL Customer Complaint)				
2	10-KCPE-809-COM (KCPL Customer Complaint)				
3	10-KCPE-795-TAR (KCPL Demand Side Mngmt Prgms)				
4	10-KCPE-636-TAR (KCPL 2010 Energy Effic Rider)				
5	10-KCPE-548-ACA (KCPL 2009 Actual Cost Adjmt)				
6	10-KCPE-456-CON (KCPL/KCPL GMO Joint Op Agmt)				
7	11-KCPE-031-COM (KCPL Customer Complaint)				
8	10-BHCG-639-TAR (Intrvn BH 5Yr Enrgy Eff Plan)				
9	10-EPDE-314-RTS (Empire District 2010 Rt Cs)				
10	10-EPDE-497-TAR (Empire District EE Programs)				
11	10-KEPE-262-MIS (Funding Wolf Crk Decom Costs)				
12	10-KGSG-421-TAR (Intrvne Kansas Gas EE Prgms)				
13	Total Other Kansas Regulatory Proceedings		4,195,908	4,195,908	
14					
15	Kansas 2006 Rate Case				
16	Amortize 1/2007 - 12/2010		304,330	304,330	304,330
17					
18	Kansas 2007 Rate Case				
19	Amortize 1/2008 - 12/2011		223,943	223,943	437,241
20					
21	Kansas 2009 Rate Case				
22	Amortize 8/2009 - 7/2013		591,968	591,968	2,073,226
23					
24	Kansas 2010 Rate Case		118,119	118,119	1,823,621
25	Amortize 12/2010 - 11/2014				
26					
27	Misc Tariff Fillings & Reg Comm Exp (MO & KS)		32,627	32,627	
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	1,897,956	8,885,405	10,783,361	7,364,021

REGULATORY COMMISSION EXPENSES (Continued)

- 3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
- 4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
- 5. Minor items (less than \$25,000) may be grouped.

EXPENSES INCURRED DURING YEAR			AMORTIZED DURING YEAR				
CURRENTLY CHARGED TO			Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
Department (f)	Account No. (g)	Amount (h)					
Electric	928	1,194,983					1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
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							16
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							37
							38
							39
							40
							41
							42
							43
							44
		10,783,361	6,679,092		1,761,355	12,281,758	46

REGULATORY COMMISSION EXPENSES (Continued)

- 3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
- 4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
- 5. Minor items (less than \$25,000) may be grouped.

EXPENSES INCURRED DURING YEAR			AMORTIZED DURING YEAR				Line No.
CURRENTLY CHARGED TO			Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	
Department (f)	Account No. (g)	Amount (h)					
							1
Electric	928	581,579					2
							3
							4
Electric	928	955,808					5
							6
							7
Electric	928	34,677					8
							9
							10
							11
							12
							13
							14
							15
							16
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							38
							39
							40
							41
							42
							43
							44
							45
		10,783,361	6,679,092		1,761,355	12,281,758	46

REGULATORY COMMISSION EXPENSES (Continued)

- 3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
- 4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
- 5. Minor items (less than \$25,000) may be grouped.

EXPENSES INCURRED DURING YEAR			AMORTIZED DURING YEAR				
CURRENTLY CHARGED TO			Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
Department (f)	Account No. (g)	Amount (h)					
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
							15
							16
							17
Electric	928	1,084,276					18
							19
							20
Electric	928	522,995			522,995	348,664	21
							22
			2,739,483			4,593,427	23
							24
							25
Electric	928	850,021					26
Electric	928	92,127					27
							28
							29
							30
							31
							32
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							35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		10,783,361	6,679,092		1,761,355	12,281,758	46

REGULATORY COMMISSION EXPENSES (Continued)

- 3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
- 4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
- 5. Minor items (less than \$25,000) may be grouped.

EXPENSES INCURRED DURING YEAR			AMORTIZED DURING YEAR				
CURRENTLY CHARGED TO			Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
Department (f)	Account No. (g)	Amount (h)					
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
Electric	928	4,195,908					13
							14
							15
Electric	928	304,330			304,330		16
							17
							18
Electric	928	223,943			223,943	213,299	19
							20
							21
Electric	928	591,968	-24,601		591,968	1,456,657	22
							23
		118,119	3,964,210		118,119	5,669,711	24
							25
							26
Electric	928	32,627					27
							28
							29
							30
							31
							32
							33
							34
							35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		10,783,361	6,679,092		1,761,355	12,281,758	46

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kansas City Power & Light Company		04/15/2011	2010/Q4
FOOTNOTE DATA			

Schedule Page: 350.1 Line No.: 2 Column: c

Per Docket No. ER10-230-000, FERC transmission formula rate, additional detail for FERC Transmission Regulatory Commission expense has been provided below:

FERC Transmission Formula Rate Docket ER10-230-000	326,728
E-Tariff (Transmission)	11,224
All Other FERC Regulatory Commission Expense	243,627
Total FERC Regulatory Proceedings	581,579

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects. (Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

- | | |
|--|--|
| A. Electric R, D & D Performed Internally: | a. Overhead |
| (1) Generation | b. Underground |
| a. hydroelectric | (3) Distribution |
| i. Recreation fish and wildlife | (4) Regional Transmission and Market Operation |
| ii Other hydroelectric | (5) Environment (other than equipment) |
| b. Fossil-fuel steam | (6) Other (Classify and include items in excess of \$50,000.) |
| c. Internal combustion or gas turbine | (7) Total Cost Incurred |
| d. Nuclear | B. Electric, R, D & D Performed Externally: |
| e. Unconventional generation | (1) Research Support to the electrical Research Council or the Electric Power Research Institute |
| f. Siting and heat rejection | |
| (2) Transmission | |

Line No.	Classification (a)	Description (b)
1	B(1) Research Support to EPRI	Fuel Planning Research
2		
3		
4		
5	B(1) Research Support to EPRI	Carbon Capture Storage
6		
7	B(1) Research Support to EPRI	Compressed Air Demonstration
8		
9	B(1) Research Support to EPRI	Energy Efficiency Demonstration
10		
11	B(1) Research Support to EPRI	Smart Grid Demonstration
12		
13		
14	B(1) Research Support to EPRI	Research Support to EPRI
15		
16		
17	B(5) Total	
18		
19		
20		
21		
22		
23		
24		
25		
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38		

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

- (2) Research Support to Edison Electric Institute
- (3) Research Support to Nuclear Power Groups
- (4) Research Support to Others (Classify)
- (5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing \$50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under \$50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.

4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)

5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.

6. If costs have not been segregated for R, D & D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."

7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
4,420		557	4,420		1
327		408.1	327		2
1,854		926	1,854		3
					4
318,875		557	318,875		5
					6
82,908		557	82,908		7
					8
86,513		588	86,513		9
					10
74,977		588	74,977		11
385		921	385		12
					13
2,800,309		930.2	2,800,309		14
				107,450	15
					16
3,370,568			3,370,568	107,450	17
					18
					19
					20
					21
					22
					23
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					38

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report 2010/Q4
Kansas City Power & Light Company			
FOOTNOTE DATA			

Schedule Page: 352 Line No.: 14 Column: f

Additional detail for specific Transmission Research and Development expenses, to be used in the FERC Transmission Formula Rate per settlement of Docket No. ER10-230-000, has been provided below:

Transmission Specific Projects/Programs:	
Transmission Environmental Issues	\$ 83,897
Transmission Lines & Substation Reliability	252,641
Transmission Grid Operations	95,071
Efficient Transmission Systems	54,978
Total Transmission Specific Project/Programs	<u>486,587</u>
Other Research & Development Expenses	<u>2,313,722</u>
Total Page 353, Line 14, Column f	\$2,800,309

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	169,344,767	5,384,682	174,729,449
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	37,381,822	10,835,902	48,217,724
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	37,381,822	10,835,902	48,217,724
72	Plant Removal (By Utility Departments)			
73	Electric Plant	4,956,839	294,556	5,251,395
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	4,956,839	294,556	5,251,395
77	Other Accounts (Specify, provide details in footnote):			
78	Misc Income Deductions	1,009,558	10,570	1,020,128
79	Unit Trains	77,754	-452,232	-374,478
80	Miscellaneous & Billing Work Orders	1,115,462	53,430	1,168,892
81	Nuclear Fuel (120100)	251,050	-7,372	243,678
82	Deferred Customer Programs	823,499	8,200	831,699
83	latan 2 Constr Accounting	481,636	5,327	486,963
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	3,758,959	-382,077	3,376,882
96	TOTAL SALARIES AND WAGES	215,442,387	16,133,063	231,575,450

Name of Respondent Kansas City Power & Light Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of <u>2010/Q4</u>
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COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	1,365,765	629,847	1,948,577	480,215
3	Net Sales (Account 447)	(8,962,487)	(10,831,029)	(15,823,530)	(9,776,451)
4	Transmission Rights				
5	Ancillary Services	63,175	88,389	67,093	108,704
6	Other Items (list separately)				
7	Other RTO Charges (net)	306,970	753,811	98,875	177,316
8					
9					
10					
11					
12					
13					
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15					
16					
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18					
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42					
43					
44					
45					
46	TOTAL	(7,226,577)	(9,358,982)	(13,708,985)	(9,010,216)

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
 (2) Report on Column (b) by month the transmission system's peak load.
 (3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
 (4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM: Kansas City Power & Light Company

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	3,014	7	1900	2,811	72		131		
2	February	2,635	9	800	2,445	59		131		
3	March	2,299	1	1900	2,113	54		132		
4	Total for Quarter 1	7,948			7,369	185		394		
5	April	2,199	14	1700	2,018	49		132		
6	May	3,030	24	1700	2,825	74		131		
7	June	3,626	22	1700	3,398	97		131		
8	Total for Quarter 2	8,855			8,241	220		394		
9	July	3,643	20	1600	3,412	100		131		
10	August	3,841	13	1600	3,603	107		131		
11	September	3,161	20	1700	2,947	82		132		
12	Total for Quarter 3	10,645			9,962	289		394		
13	October	2,273	8	1600	2,086	55		132		
14	November	2,408	30	1900	2,220	56		132		
15	December	2,631	13	800	2,442	58		131		
16	Total for Quarter 4	7,312			6,748	169		395		
17	Total Year to Date/Year	34,760			32,320	863		1,577		

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

- (1) Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
- (2) Report on Column (b) by month the transmission system's peak load.
- (3) Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
- (4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
- (5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM:

Line No.	Month	Monthly Peak MW - Total	Day of Monthly Peak	Hour of Monthly Peak	Imports into ISO/RTO	Exports from ISO/RTO	Through and Out Service	Network Service Usage	Point-to-Point Service Usage	Total Usage
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

Name of Respondent
 Kansas City Power & Light Company

This Report Is:
 (1) An Original
 (2) A Resubmission

Date of Report
 (Mo, Da, Yr)
 04/15/2011

Year/Period of Report
 End of 2010/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	15,466,993
3	Steam	15,868,540	23	Requirements Sales for Resale (See instruction 4, page 311.)	113,423
4	Nuclear	4,491,166	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	5,937,524
5	Hydro-Conventional		25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	24,783
7	Other	670,185	27	Total Energy Losses	946,007
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	22,488,730
9	Net Generation (Enter Total of lines 3 through 8)	21,029,891			
10	Purchases	1,458,839			
11	Power Exchanges:				
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	478,319			
17	Delivered	478,319			
18	Net Transmission for Other (Line 16 minus line 17)				
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	22,488,730			

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirements Sales for Resale & Associated Losses (c)	MONTHLY PEAK		
				Megawatts (See Instr. 4) (d)	Day of Month (e)	Hour (f)
29	January	2,043,340	531,866	2,811	7	1900
30	February	1,615,770	308,253	2,445	9	800
31	March	1,543,690	306,344	2,113	1	1900
32	April	1,650,550	536,564	2,018	14	1700
33	May	1,769,972	493,950	2,825	24	1700
34	June	2,027,833	439,180	3,398	22	1700
35	July	2,110,536	367,364	3,412	20	1600
36	August	2,271,540	515,788	3,603	13	1600
37	September	1,997,871	701,417	2,947	20	1700
38	October	1,763,624	634,219	2,086	8	1600
39	November	1,749,576	633,918	2,220	30	1900
40	December	1,944,428	468,661	2,442	13	800
41	TOTAL	22,488,730	5,937,524			

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a term basis report the Btu content of the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: <i>Montrose</i> (b)	Plant Name: <i>Hawthorn 5</i> (c)				
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Steam	Steam				
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Full Outdoor	Full Outdoor				
3	Year Originally Constructed	1958	1969				
4	Year Last Unit was Installed	1964	1969				
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	563.00	594.00				
6	Net Peak Demand on Plant - MW (60 minutes)	520	561				
7	Plant Hours Connected to Load	8417	7608				
8	Net Continuous Plant Capability (Megawatts)	0	0				
9	When Not Limited by Condenser Water	510	476				
10	When Limited by Condenser Water	0	0				
11	Average Number of Employees	125	129				
12	Net Generation, Exclusive of Plant Use - KWh	3151503000	3847404000				
13	Cost of Plant: Land and Land Rights	1406842	807281				
14	Structures and Improvements	16562337	34538782				
15	Equipment Costs	206128940	440474171				
16	Asset Retirement Costs	6877641	8813288				
17	Total Cost	230975760	484633522				
18	Cost per KW of Installed Capacity (line 17/5) Including	410.2589	815.8814				
19	Production Expenses: Oper, Supv, & Engr	1066473	1389935				
20	Fuel	65352701	51232045				
21	Coolants and Water (Nuclear Plants Only)	0	0				
22	Steam Expenses	2916116	4092121				
23	Steam From Other Sources	0	0				
24	Steam Transferred (Cr)	0	0				
25	Electric Expenses	1825135	1285347				
26	Misc Steam (or Nuclear) Power Expenses	3158083	2941784				
27	Rents	26466	129453				
28	Allowances	0	-140103				
29	Maintenance Supervision and Engineering	1494235	1768062				
30	Maintenance of Structures	851402	1946763				
31	Maintenance of Boiler (or reactor) Plant	6729409	10364014				
32	Maintenance of Electric Plant	1033240	1870954				
33	Maintenance of Misc Steam (or Nuclear) Plant	50930	29138				
34	Total Production Expenses	84504190	76909513				
35	Expenses per Net KWh	0.0268	0.0200				
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil		Coal	Gas	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Coal-tons	Oil-barrel		Coal-tons	Gas-mcf	
38	Quantity (Units) of Fuel Burned	1987510	27157	0	2265683	93630	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	8642	137608	0	8418	1000	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	31.078	95.893	0.000	18.742	9.191	0.000
41	Average Cost of Fuel per Unit Burned	31.172	89.838	0.000	19.412	9.191	0.000
42	Average Cost of Fuel Burned per Million BTU	3117.243	1554.414	0.000	1941.204	919.087	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.020	0.000	0.000	0.012	0.000	0.000
44	Average BTU per KWh Net Generation	10950.393	0.000	0.000	9938.241	0.000	0.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: <i>latan 1 (100%)</i> (b)	Plant Name: <i>latan 1 (70%)</i> (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Steam	Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor Boiler	Outdoor Boiler
3	Year Originally Constructed	1980	1980
4	Year Last Unit was Installed	1980	1980
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	726.00	508.00
6	Net Peak Demand on Plant - MW (60 minutes)	0	510
7	Plant Hours Connected to Load	0	7889
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	670	469
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	169	0
12	Net Generation, Exclusive of Plant Use - KWh	5176377800	3627192800
13	Cost of Plant: Land and Land Rights	0	4325109
14	Structures and Improvements	0	53119418
15	Equipment Costs	0	556585647
16	Asset Retirement Costs	0	70544
17	Total Cost	0	614100718
18	Cost per KW of Installed Capacity (line 17/5) Including	0.0000	1208.8597
19	Production Expenses: Oper, Supv, & Engr	0	1580168
20	Fuel	0	44844103
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	4181373
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	0	1403168
26	Misc Steam (or Nuclear) Power Expenses	0	1843879
27	Rents	0	2672
28	Allowances	0	0
29	Maintenance Supervision and Engineering	0	267669
30	Maintenance of Structures	0	850140
31	Maintenance of Boiler (or reactor) Plant	0	4697618
32	Maintenance of Electric Plant	0	491523
33	Maintenance of Misc Steam (or Nuclear) Plant	0	159766
34	Total Production Expenses	0	60322079
35	Expenses per Net KWh	0.0000	0.0166
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)		Coal Oil
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)		Coal-tons Oil-barrels
38	Quantity (Units) of Fuel Burned	0 0 0	2112346 14099 0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0 0 0	8572 136819 0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000 0.000 0.000	18.817 100.326 0.000
41	Average Cost of Fuel per Unit Burned	0.000 0.000 0.000	18.968 93.823 0.000
42	Average Cost of Fuel Burned per Million BTU	0.000 0.000 0.000	1896.768 1632.730 0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000 0.000 0.000	0.011 0.000 0.000
44	Average BTU per KWh Net Generation	0.000 0.000 0.000	10006.949 0.000 0.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a term basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: <i>Northeast</i> (b)	Plant Name: <i>Wolf Creek (47%)</i> (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Internal Combustion	Nuclear
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Full Outdoor	Full Indoor
3	Year Originally Constructed	1972	1985
4	Year Last Unit was Installed	1977	1985
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	491.00	581.00
6	Net Peak Demand on Plant - MW (60 minutes)	164	569
7	Plant Hours Connected to Load	71	8164
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	0	550
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	6	1003
12	Net Generation, Exclusive of Plant Use - KWh	-1223280	4491166000
13	Cost of Plant: Land and Land Rights	285450	3411585
14	Structures and Improvements	1130323	420878975
15	Equipment Costs	49814492	962655564
16	Asset Retirement Costs	229609	0
17	Total Cost	51459874	1386946124
18	Cost per KW of Installed Capacity (line 17/5) Including	104.8063	2387.1706
19	Production Expenses: Oper, Supv, & Engr	104655	5964702
20	Fuel	463851	29169655
21	Coolants and Water (Nuclear Plants Only)	0	2356535
22	Steam Expenses	450	9963704
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	374313	890864
26	Misc Steam (or Nuclear) Power Expenses	1015	26615136
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	549	3746591
30	Maintenance of Structures	81704	2194789
31	Maintenance of Boiler (or reactor) Plant	23	10076586
32	Maintenance of Electric Plant	186267	2825079
33	Maintenance of Misc Steam (or Nuclear) Plant	0	8361672
34	Total Production Expenses	1212827	102165313
35	Expenses per Net KWh	-0.9915	0.0227
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Oil	Nuclear
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Oil-barrels	Nuclear-m
38	Quantity (Units) of Fuel Burned	6158	46377652
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	136864	137980
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	88.525	97.581
41	Average Cost of Fuel per Unit Burned	75.001	85.795
42	Average Cost of Fuel Burned per Million BTU	1304.760	62.621
43	Average Cost of Fuel Burned per KWh Net Gen	-0.378	0.006
44	Average BTU per KWh Net Generation	-28936.956	10328.338

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)(Continued)

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: Hawthorn 6 & 9 (d)			Plant Name: Hawthorn 7 & 8 (e)			Plant Name: Osawatomie (f)			Line No.
Combined Cycle			Gas Turbine			Gas Turbine			1
Full Outdoor			Full Outdoor			Full Outdoor			2
2000			2000			2003			3
2000			2000			2003			4
301.00			164.00			102.00			5
264			154			76			6
2976			159			32			7
0			0			0			8
281			154			0			9
0			0			0			10
0			0			0			11
221044000			6749000			1474000			12
0			0			694545			13
2382585			788537			1571882			14
117613845			53725813			29997697			15
64655			0			0			16
120061085			54514350			32264124			17
398.8740			332.4046			316.3149			18
543807			-8902			23876			19
10251082			526680			136340			20
0			0			0			21
280833			0			0			22
0			0			0			23
0			0			0			24
1341940			92732			46954			25
-1219			5			0			26
0			0			0			27
0			0			0			28
57125			1200			16			29
109194			3658			6879			30
320920			18			0			31
1548345			251994			17623			32
0			0			0			33
14452027			867385			231688			34
0.0654			0.1285			0.1572			35
Gas			Gas			Gas			36
Gas-mcf			Gas-mcf			Gas-mcf			37
1977410	0	0	99642	0	0	25862	0	0	38
1000	0	0	1000	0	0	1000	0	0	39
5.129	0.000	0.000	5.257	0.000	0.000	5.244	0.000	0.000	40
5.129	0.000	0.000	5.257	0.000	0.000	5.244	0.000	0.000	41
512.908	0.000	0.000	525.731	0.000	0.000	524.432	0.000	0.000	42
0.046	0.000	0.000	0.078	0.000	0.000	0.092	0.000	0.000	43
8945.776	0.000	0.000	14763.965	0.000	0.000	17545.455	0.000	0.000	44

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)(Continued)

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: <i>latan 2 (100%)</i> (d)			Plant Name: <i>latan 2 (54.71%)</i> (e)			Plant Name: <i>West Gardner</i> (f)			Line No.
	Steam			Steam			Gas Turbine		1
	Outdoor Boiler			Outdoor Boiler			Full Outdoor		2
	2010			2010			2003		3
	2010			2010			2003		4
	999.00			547.00			408.00		5
	0			500			325		6
	0			8666			424		7
	0			0			0		8
	850			465			0		9
	0			0			0		10
	36			0			5		11
	1212534800			776632800			76221000		12
	0			0			271105		13
	0			138076588			2801658		14
	0			972583323			120075191		15
	0			0			0		16
	0			1110659911			123147954		17
	0.0000			2030.4569			301.8332		18
	0			882233			608075		19
	0			4629087			6166466		20
	0			0			0		21
	0			150415			0		22
	0			0			0		23
	0			0			0		24
	0			40100			137884		25
	0			74694			207		26
	0			2825			0		27
	0			0			0		28
	0			16721			2254		29
	0			189215			80588		30
	0			1087856			427		31
	0			60643			30733		32
	0			22419			0		33
	0			7156208			7026634		34
	0.0000			0.0092			0.0922		35
			Coal	Oil		Gas			36
			Coal-tons	Oil-barrels		Gas-mcf			37
0	0	0	423826	13010	0	1038053	0	0	38
0	0	0	8628	135902	0	1000	0	0	39
0.000	0.000	0.000	18.817	100.326	0.000	5.913	0.000	0.000	40
0.000	0.000	0.000	19.794	96.975	0.000	5.913	0.000	0.000	41
0.000	0.000	0.000	1979.429	1698.969	0.000	591.321	0.000	0.000	42
0.000	0.000	0.000	0.006	0.000	0.000	0.081	0.000	0.000	43
0.000	0.000	0.000	9512.807	0.000	0.000	13618.990	0.000	0.000	44

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)(Continued)

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: LaCygne 1 (50%) (d)			Plant Name: LaCygne 2 (50%) (e)			Plant Name: LaCygne (100%) (f)			Line No.
Steam			Steam			Steam			1
Full Outdoor			Full Outdoor			Full Outdoor			2
1973			1973			1973			3
1977			1977			1977			4
436.50			362.93			1654.00			5
375			348			0			6
6714			7564			0			7
0			0			0			8
681			681			1362			9
0			0			0			10
0			0			241			11
2207815000			2257992000			8920856000			12
2321637			383925			0			13
20206936			4885038			0			14
230392485			145903986			0			15
1698071			0			0			16
254619129			151172949			0			17
583.3199			416.5347			0.0000			18
526421			617854			0			19
35127652			31087865			0			20
0			0			0			21
2787246			1759477			0			22
0			0			0			23
0			0			0			24
664020			692703			0			25
940172			928619			0			26
16847			16683			0			27
0			0			0			28
1314873			1211470			0			29
902542			711398			0			30
4214044			4522031			0			31
415531			306195			0			32
48182			48105			0			33
46957530			41902400			0			34
0.0213			0.0186			0.0000			35
Coal	Oil		Coal	Oil					36
Coal-tons	Oil-barrel		Coal-tons	Oil-barrel					37
1328673	12503	0	1366028	8322	0	0	0	0	38
8668	137399	0	8430	137265	0	0	0	0	39
21.402	95.260	0.000	21.402	95.260	0.000	0.000	0.000	0.000	40
23.232	89.181	0.000	21.364	90.626	0.000	0.000	0.000	0.000	41
2323.165	1545.393	0.000	2136.429	1571.958	0.000	0.000	0.000	0.000	42
0.014	0.000	0.000	0.013	0.000	0.000	0.000	0.000	0.000	43
10465.871	0.000	0.000	10220.599	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report 2010/Q4
Kansas City Power & Light Company			
FOOTNOTE DATA			

Schedule Page: 402 Line No.: 1 Column: f
Osawatomie is designed for peak load service.

Schedule Page: 402 Line No.: 7 Column: b
Montrose Station is comprised of three units. Hours reported are for the unit connected to the load the longest.

Schedule Page: 402 Line No.: 7 Column: d
Hawthorn 6&9 is comprised of two units. Hours reported are for the unit connected to the load the longest.

Schedule Page: 402 Line No.: 7 Column: e
Hawthorn 7&8 is comprised of two units. Hours reported are for the unit connected to the load the longest.

Schedule Page: 402.1 Line No.: -1 Column: c
Kansas City Power & Light owns 70% of Iatan 1 Station.

Schedule Page: 402.1 Line No.: -1 Column: e
Kansas City Power & Light owns 54.71% of Iatan 2 Station.

Schedule Page: 402.1 Line No.: 1 Column: f
West Gardner is designed for peak load service.

Schedule Page: 402.1 Line No.: 11 Column: b
There are 205 employees at the Iatan plant. There are 30 operators and 6 shift foremen for each unit. The remainder of the employees are considered common employees and are assigned as necessary. These common employees have been included in the total number for Iatan 1.

Schedule Page: 402.2 Line No.: -1 Column: c
Wolf Creek is a nuclear generating plant with a pressurized water reactor. The design is by Standard Nuclear Unit Power Plant System (SNUPPS). The plant is operated by the Wolf Creek Nuclear Operating Corporation. Wolf Creek is jointly owned by Kansas City Power & Light Company (47%), Kansas Gas and Electric Company (47%) and Kansas Electric Power Cooperative, Inc. (6%).

Schedule Page: 402.2 Line No.: -1 Column: d
Kansas City Power & Light owns 50% of LaCygne 1 Station.

Schedule Page: 402.2 Line No.: -1 Column: e
Kansas City Power & Light owns 50% of LaCygne 2 Station.

Schedule Page: 402.2 Line No.: 7 Column: b
Northeast is comprised of eight units. Hours reported are for the unit connected to the load the longest.

Schedule Page: 402.2 Line No.: 16 Column: d
ARO amount includes both LaCygne Unit 1 and Unit 2.

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. Plant Name: (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demand on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per KWh (line 37 / 9)	

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.

7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
			1
			2
			3
			4
			5
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			37
			38

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Spearville Wind Energy Facility		148.50	151.0	365,921,000	261,191,737
2	(67 Units @1.5MW each)	2006				
3	(32 Units @1.5 MW each)	2010				
4						
5						
6						
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GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents per Million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
1,758,867	848,431		1,429,303	wind		1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
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						46

Name of Respondent Kansas City Power & Light Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Schedule Page: 410 Line No.: 1 Column: a

Net generation, cost of plant, operation expense and maintenance expense are not tracked separately for each set of wind turbine units; therefore, totals have been included in Line No 1.

Schedule Page: 410 Line No.: 1 Column: e

Amounts reported for net generation are in Kwh.

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	Missouri (Overhead Lines):							
2	Stilwell	Sibley	345.00	345.00	Wd-H-Frame	5.22		1
3	Sibley	Overton	345.00	345.00	Wd-H-Frame	73.02		1
4	Hawthorn	Nashua-St. Joe	345.00	345.00	Wd-H-Frame	31.33		1
5	River X Iatan	Stranger Creek Jct	345.00	345.00	Tower	0.34		1
6	Iatan	Stranger Creek Jct	345.00	345.00	Wd-H-Frame	1.38		1
7	Hawthorn	Sibley	345.00	345.00	Wd-H-Frame	17.76		1
8	DC River X Hawthorn	Nashua/Sibley	345.00	345.00	Tower	0.57		2
9	River X Hawthorn	Sibley	345.00	345.00	Tower	0.44		1
10	Total 345 Kv					130.06		9
11	Common R/W	Hawthorn Plant	161.00	161.00				
12	Hawthorn	Blue Valley Tower	161.00	161.00	Tower	1.82		1
13	Hawthorn	Leeds Tower	161.00	161.00	Wd-H-Frame	1.37		1
14	Blue Valley Tower	Blue Valley	161.00	161.00	Tower	0.51		3
15	Hawthorn	Randolph-Avon	161.00	161.00	Wd-H-Frame	5.08		1
16	TC River X	Hawthorn	161.00	161.00	Tower	0.54		3
17	DC River X	Northeast	161.00	161.00	Tower	0.36		2
18	Blue Valley	Winchester Jct	161.00	161.00	Wd-H-Frame	7.92		1
19	Leeds Tower	Loma Vista	161.00	161.00	Wd-H-Frame	11.03		1
20	Southtown	Bunker Ridge	161.00	161.00	Wd-H-Frame	3.08		1
21	Northeast	Grand Ave	161.00	161.00	Wd-H-Frame	0.13		1
22	Blue Mills Jct	Blue Mills #2	161.00	161.00	Wood Pole	0.23		1
23	Leeds	Roeland Park	161.00	161.00	Wd-H-Frame	2.31		1
24	DC Southtown	Hickman/Grandview	161.00	161.00	Wd-H-Frame	0.11		2
25	DC Montrose	Loma Vista	161.00	161.00	Tower	0.97		2
26	Grand Ave	Navy-Terrace	161.00	161.00	Wd-H-Frame	1.95		1
27	Common R/W	Hawthorn-Southtown	161.00	161.00				
28	Northeast	Crosstown	161.00	161.00	Stl Pl / Tower	0.19		1
29	Maywood	Weatherby	161.00	161.00	Stl Pl/Wd-H-Fr	5.19		1
30	DC NE-Grand Ave	Hawthorn-Crosstown	161.00	161.00	Tower	0.21		2
31	Henry	Rw Montrose-Stilwell	161.00	161.00	Wd-Pole			1
32	Montrose	Stilwell #13	161.00	161.00	Wood Pole	48.20		1
33	Montrose	Loma Vista #9	161.00	161.00	Wd-H-Frame	57.26		1
34	Montrose	Loma Vista #11	161.00	161.00	Wd-H-Frame	57.29		1
35	Montrose	Archie-Stilwell	161.00	161.00	Wd-H-Frame	48.15		1
36					TOTAL	1,804.29		197

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	Southtown	Grandview	161.00	161.00	Wd-H-Frame	7.71		1
2	Stilwell	Hickman	161.00	161.00	Wd-H-Frame	6.64		1
3	Hawthorn	Blue Valley	161.00	161.00	Wd-H-Frame	1.71		1
4	Hawthorn	Missouri City	161.00	161.00	Wd-H-Frame	14.30		1
5	Missouri City	Moberly	161.00	161.00	Wd-H-Frame	90.23		1
6	Salisbury	Norton	161.00	161.00	Wd-H-Frame	22.28		1
7	Norton	Malta Bend-South Waverly	161.00	161.00	Wd-H-Frame	14.18		1
8	Nashua	St Joseph	161.00	161.00	Wd-H-Frame	31.14		1
9	Montrose	Clinton	161.00	161.00	Wd-H-Frame	12.22		1
10	Midtown	Forest	161.00	161.00	Steel Pole	1.62		1
11	Forest	Southtown	161.00	161.00	Steel Pole	3.24		1
12	Blue Mills Jct	Blue Mills #1	161.00	161.00	Wd-H-Frame	0.21		1
13	Midtown	Crosstown	161.00	161.00	Steel Pole	3.92		1
14	Terrace	State Line	161.00	161.00	Wd-H-Frame	0.78		1
15	Armco	Melt Shop Jct	161.00	161.00	Steel Pole	0.32		1
16	Barry	Line Creek	161.00	161.00	Wood Pole	4.19		1
17	Winchester Jct	Southtown	161.00	161.00	Wd-H-Frame	7.47		1
18	Winchester Jct	Swope #1	161.00	161.00	Wd-H-Frame	0.39		1
19	DC NKC	NE / Avondale	161.00	161.00	Steel Pole	1.16		2
20	Northeast	NKC	161.00	161.00	Steel Pole	0.16		1
21	DC Martin City	Redel / Grandview	161.00	161.00	Steel Pole	0.36		2
22	Southtown	Hickman	161.00	161.00	Wd-H-Frame	5.44		1
23	Martin City	Grandview	161.00	161.00	Wd-H-Frame	1.34		1
24	Line Creek	Riverside	161.00	161.00	Wd-Stl-Pole	4.20		1
25	Hawthorn	Independence	161.00	161.00	Steel Pole	1.75		1
26	Birmingham	Claycomo	161.00	161.00	Wd-H-Frame	4.39		1
27	Avondale	NKC	161.00	161.00	Wd-H-Frame	2.14		1
28	Northeast	Avondale	161.00	161.00	Wd-H-Frame	2.10		1
29	Avondale Jct	Riverside	161.00	161.00	Wd-St Pl/H Fr	4.47		1
30	Northeast	Grand West	161.00	161.00	Steel Pole	1.51		1
31	Bunker Ridge	Loma Vista	161.00	161.00	Wd-H-Frame	0.78		1
32	DC Bunker Ridge	Southtown/Loma Vista	161.00	161.00	Steel Pole	1.31		2
33	Weatherby	Tiffany	161.00	161.00	Stl Pl/Wd-H-Fr	3.95		1
34	Tiffany	Roanridge	161.00	161.00	Steel Pole	1.64		1
35	Roanridge	Barry	161.00	161.00	Steel Pole	2.35		1
36					TOTAL	1,804.29		197

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	Roanridge	Nashua	161.00	161.00	Stl PI/Wd-H-Fr	4.99		1
2	DC Roanridge	Barry/Nashua	161.00	161.00	Steel Pole	0.95		2
3	Hawthorn	Leeds #27	161.00	161.00	StlPI/Stl-H-Fr	6.19		1
4	Gladstone	Shoal Creek	161.00	161.00	Wd/Stl Pole	3.70		1
5	Shoal Creek	Nashua	161.00	161.00	Wd-H-Frame	6.85		1
6	Shoal Creek	Claycomo	161.00	161.00	Wd/Stl Pole	4.33		1
7	Hawthorn	Levee	161.00	161.00	Steel Pole	0.36		1
8	Levee	Northeast #17	161.00	161.00	Stl PIWd-H-Fr	5.32		1
9	Hawthorn	Chouteau	161.00	161.00	Stl/Wd-H-Fr	2.85		1
10	Chouteau	Northeast #5	161.00	161.00	Wd-H-Frame	2.37		1
11	DC Hawthorn	Leeds/Chouteau	161.00	161.00	Steel Pole	0.39		2
12	Malta Bend	S Waverly	161.00	161.00		7.63		1
13	Martin City	Redel	161.00	161.00	Wd-H-Fr	0.62		1
14	Leeds	Independence	161.00	161.00	Steel Pole	1.15		1
15	DC Leeds	Hawthorn/Independ	161.00	161.00	Steel Pole	1.03		2
16	Winchester Jct	Swope #2	161.00	161.00	Wd-H-Fr	0.48		1
17	Avondale	Gladstone	161.00	161.00	Wd Pole/H-Fr	5.74		1
18	Southtown	Bendix	161.00	161.00	Wd-H-Fr	1.35		1
19	Bendix	Tomahawk	161.00	161.00	Wd-H-Frame	4.15		1
20	Tomahawk	Mission Jct	161.00	161.00	Wd-H-Frame	3.14		1
21	Total 161 Kv					579.09		92
22	Various 66 Kv					77.29		
23	Total 66 Kv					77.29		
24	Various 33 Kv					164.30		
25	Total 33 Kv					164.30		
26	Underground Lines:							
27	Grand Ave	Guinotte Ts	161.00	161.00	Ug Const	1.34		1
28	Midtown	Brush Creek Ts	161.00	161.00	Ug Const	2.06		1
29	Midtown	Roe Ts	161.00	161.00	Ug Const	2.00		1
30	Grand Ave	Crosstown	161.00	161.00	Ug Const	2.06		1
31	Crosstown	Guinotte TS	161.00	161.00	Ug Const	2.69		1
32	Grand Ave	Navy/Terrace	161.00	161.00	Ug Const	0.18		1
33	Total 161 Kv Underground					10.33		6
34	Anderson		34.00	34.00	Ug Const			1
35	Total 34Kv Underground							1
36					TOTAL	1,804.29		197

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	Kansas (Overhead Lines)							
2	Swissvale	Stilwell	345.00	345.00	Wd-H-Frame	32.82		1
3	Stilwell	Sibley	345.00	345.00	Wd-H-Frame	3.05		1
4	LaCygne	Stilwell	345.00	345.00	Wd-H-Frame	30.78		1
5	LaCygne	W. Gardner	345.00	345.00	Wd-H-Frame	40.38		1
6	DC Craig	Gardner/Cedar Ck	345.00	345.00	Steel Pole	2.06		2
7	River X Iatan	Stranger Creek Jct	345.00	345.00	Tower	0.40		1
8	Iatan	Stranger Creek Jct	345.00	345.00	Wd-H-Frame	11.90		1
9	Stranger Creek Jct	Craig	345.00	345.00	Wd-H-Frame	28.14		1
10	Craig	W. Gardner	345.00	345.00	Wd-H-Frame	16.19		1
11	DC W Gardner	LaCygne/Craig	345.00	345.00	Steel Pole	0.05		2
12	Wolf Creek		345.00	345.00				
13	DC W Gardner	LaCygne/Ottawa	345.00	345.00	St Pole/H-Fr	0.49		2
14	Total 345 Kv					166.26		14
15	Leeds	Roeland Pk	161.00	161.00	Wd-H-Frame	0.17		1
16	Greenwood	Shawnee	161.00	161.00	Wd-H-Frame	3.12		1
17	Oxford	Olathe	161.00	161.00	Steel Pole	3.08		1
18	Mission Jct	Kenilworth	161.00	161.00	Wd-H-Frame	4.79		1
19	Overland Pk	Roeland Pk	161.00	161.00	Wd-H-Frame	7.26		1
20	Common R/W	Shawnee-Fisher Jct	161.00	161.00				
21	Maywood	Weatherby	161.00	161.00	Wd-H-Frame	5.30		1
22	Montrose	Stilwell #13	161.00	161.00	Wd-H-Frame	3.26		1
23	Montrose	Archie-Stilwell	161.00	161.00	Wd-H-Frame	3.14		1
24	Stilwell	Hickman	161.00	161.00	Wd-H-Frame	6.94		1
25	Brookridge	Overland Pk	161.00	161.00	Wd-H-Frame	1.92		1
26	Stilwell	Antioch	161.00	161.00	Wd-H-Frame	8.45		1
27	Wagstaff	Centennial	161.00	161.00	Wd-H-Frame	11.33		1
28	Paola	Marmaton	161.00	161.00	Wd-H-Frame	51.33		1
29	Paola	S. Ottawa	161.00	161.00	Wd-H-Frame	21.81		1
30	Merriam	Greenwood	161.00	161.00	Wd-H-Frame	4.41		1
31	Greenwood	Midland	161.00	161.00	Wd-H-Frame	2.23		1
32	Greenwood	Metropolitan	161.00	161.00	Wd-H-Frame	4.98		1
33	Kenilworth	Lenexa	161.00	161.00	Wood Pole	11.43		1
34	College	Olathe	161.00	161.00	Wood Pole	3.72		1
35	Craig	Lenexa	161.00	161.00	Steel Pole	0.22		1
36					TOTAL	1,804.29		197

TRANSMISSION LINE STATISTICS

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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	Craig	College	161.00	161.00	Wd-H-Frame	0.47		1
2	Craig	Greenwood #3	161.00	161.00	Wd-H-Frame	3.98		1
3	DC Craig-Greenwood	Lenexa-Kenilworth	161.00	161.00	Steel Pole	0.11		2
4	DC Craig	Lenexa/Greenwood	161.00	161.00	Steel Pole	2.73		2
5	DC Moonlight	Murlen/Gardner	161.00	161.00	Stl-Wd-Pole	0.39		2
6	Moonlight	W. Gardner	161.00	161.00	Steel Pole	5.39		1
7	Switzer	Riley	161.00	161.00	Steel Pole	1.82		1
8	Switzer	Olathe	161.00	161.00	Steel Pole	4.01		1
9	DC Switzer	Riley/Olathe	161.00	161.00	Steel Pole	0.22		2
10	DC Oxford	Antioch/Olathe	161.00	161.00	Wood Pole	1.30		2
11	Olathe	Murlen	161.00	161.00	Stl-Wd-Pole	4.58		1
12	Kenilworth	Overland Pk	161.00	161.00	Wd-H-Frame	3.28		1
13	DC Overland Pk	Brookrdg/Kenilworth	161.00	161.00	Wd-H-Frame	0.12		2
14	Centennial	Paola	161.00	161.00	Wood Pole	2.86		1
15	Gardner	Ottawa	161.00	161.00	Wd-H-Frame	24.34		1
16	Stilwell	Spring Hill	161.00	161.00	Wd-H-Frame	9.35		1
17	DC Stilwell	Redel/Spring Hill	161.00	161.00	Wd-H-Frame	1.31		2
18	Antioch	Oxford	161.00	161.00	Wd-H-Frame	4.90		1
19	W Gardner	Cedar Creek	161.00	161.00	Stl Pl/Stl-H-F	14.46		1
20	Martin City	Redel	161.00	161.00	Wd-H-Frame	2.74		1
21	Redel	Stilwell	161.00	161.00	Wd-H-Frame	4.21		1
22	Craig	Pflumm	161.00	161.00	Steel Pole	4.36		1
23	Pflumm	Overland Park	161.00	161.00	Steel Pole	1.83		1
24	Metropolitan	Maywood	161.00	161.00	Stl-Wd-H-Fr	4.97		1
25	Cedar Creek	Greenwood	161.00	161.00	Stl-Wd-Pole	9.89		1
26	DC Craig	Overland Park/College	161.00	161.00	Steel Pole	1.77		2
27	Lenexa Tap	Craig-Greenwood	161.00	161.00	Steel Pole	0.06		1
28	DC Riley	Brookridge/Switzer	161.00	161.00	Steel Pole	1.53		2
29	Brookridge	Riley	161.00	161.00	Steel Pole	2.56		1
30	Craig	Cedar Creek	161.00	161.00	Stl-Wd-H-Fr	1.30		1
31	Tomahawk	Mission Jct	161.00	161.00	Wd-H-Frame	1.73		1
32	Riley	Sprint	161.00	161.00	Steel Pole	0.90		1
33	Sprint	Mission Jct	161.00	161.00	Steel Pole	2.63		1
34	Bucyrus	Wagstaff	161.00	161.00	Wd-H-Frame	4.22		1
35	Stilwell	Bucyrus	161.00	161.00	Wd-H-Frame	3.05		1
36					TOTAL	1,804.29		197

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	Bucyrus	N Louisburg	161.00	161.00	Steel Pole	7.85		1
2	Paola	Osawatomie	161.00	161.00	Steel Pole	0.32		1
3	W Gardner	Cedar Niles	161.00	161.00	Steel Pole	8.20		1
4	DC SE Ottawa	Gardner/S Ottawa	161.00	161.00	Stl-H-Frame	1.34		2
5	Moonlight	Quarry	161.00	161.00	Wd-Stl Pole	4.82		1
6	Quarry	Murlen	161.00	161.00	Wd/Stl Pole	5.62		1
7	SE Ottawa	S Ottawa	161.00	161.00	Wd Frm/Stl Pl	1.46		1
8	W Gardner	Bull Creek	161.00	161.00		0.26		1
9	Total 161 Kv					322.13		73
10	Windfarm	Spearville	230.00	230.00	Steel Pole	0.31		1
11	Total 230 Kv					0.31		1
12	Various 66 Kv					2.01		
13	Total 66 Kv					2.01		
14	Various 33 Kv					350.68		
15	Total 33 Kv					350.68		
16	Underground Lines:							
17	Midtown	Roe TS	161.00	161.00	UG Const	1.83		1
18	Transmission Line Expenses							
19	Overhead							
20	Underground							
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	1,804.29		197

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
795M-AL	76,506	441,777	518,283					2
795M-AL	445,796	5,674,022	6,119,818					3
795M-AL	771,067	3,762,103	4,533,170					4
954M-AL		562,514	562,514					5
954M-AL		422,333	422,333					6
795M-AL	456,349	1,577,776	2,034,125					7
795M-AL	3,593	580,777	584,370					8
795M-AL	27,465	368,904	396,369					9
	1,780,776	13,390,206	15,170,982					10
	52,652		52,652					11
1192M-AL	1,348	295,551	296,899					12
1192M-AL	48,173	448,420	496,593					13
1192M-AL	82,960	291,126	374,086					14
1192M-AL	52,016	1,665,564	1,717,580					15
1192M-AL	2,533	548,053	550,586					16
1192M-AL		171,236	171,236					17
1192M-AL	228,268	1,120,686	1,348,954					18
1192M-AL	208,401	1,023,267	1,231,668					19
1192M-AL	44,167	365,322	409,489					20
1192M-AL	31,656	668,852	700,508					21
795M-AL		53,208	53,208					22
1192M-AL	76,527	284,517	361,044					23
1192M-AL		77,369	77,369					24
1192M-AL		345,839	345,839					25
1192M-AL	85,667	764,692	850,359					26
	79,514		79,514					27
1192M-AL		418,009	418,009					28
1192M-AL	188,104	425,960	614,064					29
1192M-AL		60,727	60,727					30
		228,911	228,911					31
1192M-AL	144,576	2,296,613	2,441,189					32
1192M-AL	305,069	2,594,050	2,899,119					33
1192M-AL	313,956	2,973,058	3,287,014					34
1192M-AL	140,512	1,676,377	1,816,889					35
	25,794,641	220,754,319	246,548,960	177,175	3,797,957	2,380,688	6,355,820	36

TRANSMISSION LINE STATISTICS (Continued)

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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.

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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1192M-AL	26,674	1,307,402	1,334,076					1
1192M-AL	202,848	611,771	814,619					2
1192M-AL		206,031	206,031					3
556M-AL	54,414	790,959	845,373					4
556M-AL	111,599	3,799,589	3,911,188					5
795M-AL	69,438	949,226	1,018,664					6
795M-AL	68,625	805,591	874,216					7
397M-AL	175,716	1,575,810	1,751,526					8
795M-AL	70,936	1,850,242	1,921,178					9
1192M-AL		328,845	328,845					10
1192M-AL		678,375	678,375					11
795M-AL	2,839	25,805	28,644					12
1192M-AL	1,909,657	5,009,184	6,918,841					13
1192M-AL		152,273	152,273					14
556M-AL	504	78,372	78,876					15
1192M-AL	356,681	581,324	938,005					16
1192M-AL	26,316	1,036,149	1,062,465					17
1192M-AL	20,400	165,303	185,703					18
1192M-AL	85,589	905,470	991,059					19
1192M-AL		151,542	151,542					20
1192M-AL		219,013	219,013					21
1192M-AL	73,499	905,493	978,992					22
1192M-AL		112,884	112,884					23
1192M-AL	1,195,041	1,204,295	2,399,336					24
1192M-AL	6	15	21					25
1192M-AL	122,386	1,518,251	1,640,637					26
1192M-AL		348,549	348,549					27
1192M-AL		100,252	100,252					28
1192M-AL	76,838	1,104,187	1,181,025					29
1192M-AL	37,215	1,140,396	1,177,611					30
1192M-AL	77,428	84,904	162,332					31
1192M-AL		381,686	381,686					32
1192M-AL	112,393	532,379	644,772					33
1192M-AL	44,957	360,450	405,407					34
1192M-AL	95,111	574,894	670,005					35
	25,794,641	220,754,319	246,548,960	177,175	3,797,957	2,380,688	6,355,820	36

TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1192M-AL	188,750	411,619	600,369					1
1192M-AL		514,888	514,888					2
1192M-AL	822,714	3,509,116	4,331,830					3
1192M-AL	134,856	771,326	906,182					4
1192M-AL	845,342	1,300,546	2,145,888					5
1192M-AL	197,910	582,832	780,742					6
1192M-AL		204,426	204,426					7
1192M-AL	12,198	1,446,958	1,459,156					8
1192M-AL	31,708	1,200,858	1,232,566					9
1192M-AL	19,393	992,620	1,012,013					10
1192M-AL		490,453	490,453					11
	29,156	248,484	277,640					12
1192M-AL		48,265	48,265					13
1192M-AL	9	7	16					14
1192M-AL		59,005	59,005					15
1192M-AL		229,104	229,104					16
1192M-AL	5,970	1,113,462	1,119,432					17
1192M-AL	51,926	443,902	495,828					18
1192M-AL	80,782	694,508	775,290					19
1192M-AL	24,504	418,640	443,144					20
	9,548,427	63,075,337	72,623,764					21
	458,508	12,156,833	12,615,341					22
	458,508	12,156,833	12,615,341					23
	296,120	12,582,311	12,878,431					24
	296,120	12,582,311	12,878,431					25
								26
2500M-CO		535,502	535,502					27
2500M-CO		995,631	995,631					28
2500M-CO		1,218,806	1,218,806					29
2500M-CO		932,287	932,287					30
2500M-CO		1,350,708	1,350,708					31
2500M-CO		148,975	148,975					32
		5,181,909	5,181,909					33
500M-AL		229,961	229,961					34
		229,961	229,961					35
	25,794,641	220,754,319	246,548,960	177,175	3,797,957	2,380,688	6,355,820	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
795M-AL	207,326	3,046,687	3,254,013					2
795M-AL	37,478	263,871	301,349					3
795M-AL	369,948	9,400,367	9,770,315					4
954M-AL	681,536	13,105,471	13,787,007					5
954M-AL		748,720	748,720					6
954M-AL		559,252	559,252					7
954M-AL	447,286	1,684,026	2,131,312					8
954M-AL	1,313,316	4,446,535	5,759,851					9
954M-AL	1,135,735	1,272,883	2,408,618					10
954M-AL		75,237	75,237					11
954M-AL	355	103,731	104,086					12
954M-AL		369,569	369,569					13
	4,192,980	35,076,349	39,269,329					14
1192M-AL	1,783	24,020	25,803					15
1192M-AL	7,793	306,456	314,249					16
1192M-AL	43,596	212,367	255,963					17
1192M-AL	113,727	466,594	580,321					18
556M-AL	280,583	807,854	1,088,437					19
	17,541		17,541					20
1192M-AL	159,387	741,333	900,720					21
1192M-AL	10,350	233,736	244,086					22
1192M-AL	9,967	94,795	104,762					23
1192M-AL	58,747	776,204	834,951					24
1192M-AL	39,850	608,843	648,693					25
1192M-AL	70,033	2,104,293	2,174,326					26
397M-AL	27,346	1,598,597	1,625,943					27
336M-AL	50,149	6,273,219	6,323,368					28
397M-AL	32,288	1,339,072	1,371,360					29
477M-AL	341,849	614,984	956,833					30
795M-AL	130,229	316,318	446,547					31
1192M-AL	362,037	699,200	1,061,237					32
1192M-AL	178,955	1,176,848	1,355,803					33
1192M-AL		283,606	283,606					34
954M-AL		26,461	26,461					35
	25,794,641	220,754,319	246,548,960	177,175	3,797,957	2,380,688	6,355,820	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1192M-AL	82,697	534,891	617,588					1
1192M-AL	151,667	226,775	378,442					2
1192M-AL	77,465	112,220	189,685					3
1192M-AL	443,416	808,963	1,252,379					4
1192M-AL	4,753	174,943	179,696					5
1192M-AL	128,482	786,399	914,881					6
1192M-AL	19,114	516,447	535,561					7
1192M-AL	33,616	385,743	419,359					8
1192M-AL	105,478	136,435	241,913					9
1192M-AL	123,083	432,663	555,746					10
1192M-AL	253,076	469,613	722,689					11
1192M-AL	166,187	674,120	840,307					12
556M-AL	8,588	67,273	75,861					13
1192M-AL		405,443	405,443					14
1192M-AL	591,458	3,694,152	4,285,610					15
1192M-AL	353,000	1,924,670	2,277,670					16
1192M-AL		571,565	571,565					17
1192M-AL		1,362,413	1,362,413					18
1192M-AL	301,786	3,644,673	3,946,459					19
1192M-AL	2,838	398,581	401,419					20
1192M-AL	4,647	272,205	276,852					21
954M-AL	430,140	2,489,028	2,919,168					22
954M-AL	175,242	1,358,783	1,534,025					23
1192M-AL		589,571	589,571					24
1192M-AL	368,060	1,753,723	2,121,783					25
1192M-AL	235,117	977,135	1,212,252					26
1192M-AL		31,755	31,755					27
1192M-AL	1,382,519	920,621	2,303,140					28
1192M-AL	26,805	702,929	729,734					29
1192M-AL		297,561	297,561					30
1192M-AL	80,554	439,181	519,735					31
1192M-AL		300,706	300,706					32
1192M-AL		820,623	820,623					33
1192M-AL	11,139	571,623	582,762					34
1192M-AL		562,714	562,714					35
	25,794,641	220,754,319	246,548,960	177,175	3,797,957	2,380,688	6,355,820	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1192M-AL	381,708	2,559,953	2,941,661					1
954M-AL		222,129	222,129					2
1192M-AL	629,412	2,929,962	3,559,374					3
1192M-AL		67	67					4
1192M-AL	241,093	628,542	869,635					5
1192M-AL	241,093	534,460	775,553					6
1192M-AL		283,359	283,359					7
954M-AL		90,512	90,512					8
	8,990,443	55,369,924	64,360,367					9
1192M-AL		401,068	401,068					10
		401,068	401,068					11
		431,132	431,132					12
		431,132	431,132					13
	527,387	22,138,192	22,665,579					14
	527,387	22,138,192	22,665,579					15
1500M-CO								16
		721,097	721,097					17
								18
				176,265	3,786,686	2,380,688	6,343,639	19
				910	11,271		12,181	20
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								31
								32
								33
								34
								35
	25,794,641	220,754,319	246,548,960	177,175	3,797,957	2,380,688	6,355,820	36

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under-ground construction and show each transmission line separately. If actual costs of completed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION		Line Length in Miles (c)	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)		Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	Stilwell	Springhill	0.28	Wd/Steel Poles	21.00		
2	Midtown	Crosstown	3.92	Steel Poles	3.00		
3							
4							
5							
6							
7							
8							
9							
10							
11							
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41							
42							
43							
44	TOTAL		4.20		24.00		

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage KV (Operating) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
1192-AL			161		319,300	132,340		451,640	1
1192-ACSS			161		2,755,051	2,254,133		5,009,184	2
									3
									4
									5
									6
									7
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					3,074,351	2,386,473		5,460,824	44

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	10-Birmingham	AC Distribution	161.00	13.00	
2	7th & Milwaukie, Clay Co, Mo.				
3	11-Barry	AC Distribution	161.00	13.00	
4	Tiffany Springs Rd, Platte Co, Mo.				
5	12-Brookridge	AC Distribution	161.00	13.00	
6	10001 W. 103rd St, Johnson Co, Ks.				
7	13-Shawnee	AC Distribution	161.00	13.00	
8	12501 W. 51st St, Johnson Co, Ks.				
9	15W-Grand Avenue West	AC Distribution	161.00	13.00	
10	2nd & Grand Ave, Jackson Co, Mo.				
11	16-Stilwell	AC Transmission	345.00	161.00	13.00
12	6300 W. 191st St, Johnson Co, Ks.	AC Distribution	161.00	13.00	
13	17-Navy	AC Distribution	161.00	13.00	
14	115 N. Main St, Jackson Co, Mo.				
15	19-Riley	AC Distribution	161.00	13.00	
16	12100 Metcalf Ave, Johnson Co, Ks.				
17	20-Reeder	AC Distribution	161.00	13.00	
18	7545 Reeder Rd, Johnson Co, Ks.				
19	22-Switzer	AC Distribution	161.00	13.00	
20	9900 W. 127th St, Johnson Co, Ks.				
21	23-Southtown	AC Distribution	161.00	13.00	
22	8627 Troost Ave, Jackson Co, Mo.				
23	24-Crosstown	AC Distribution	161.00	13.00	
24	1801 Cherry, Jackson Co, Mo.				
25	25-Glasgow	AC Distribution	34.00	13.00	
26	819 2nd St, Howard Co, Mo.				
27	27-Avondale	AC Distribution	161.00	13.00	
28	3150 Walker Rd, Clay Co, Mo.				
29	28-Sweet Springs	AC Distribution	34.00	13.00	
30	Broadway & Oak St, Saline Co, Mo.				
31	29-Lenexa	AC Distribution	161.00	13.00	
32	15730 W. 95th St, Johnson Co, Ks.				
33	30-Swope	AC Distribution	161.00	13.00	
34	6330 E. 63rd St Tfwy, Jackson Co, Mo.				
35	31-Forest	AC Distribution	161.00	13.00	
36	1105 E. 61st St, Jackson Co, Mo.				
37	35-Loma Vista	AC Distribution	161.00	13.00	
38	6620 E. 91st St, Jackson Co, Mo.				
39	37-Terrace	AC Distribution	161.00	13.00	
40	1837 Terrace St, Jackson Co, Mo.				

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	38-Oxford	AC Distribution	161.00	13.00	
2	14540 Antioch Rd, Johnson Co, Ks.				
3	39-Tiffany	AC Distribution	161.00	13.00	
4	NW of I-29 & Hwy 152, Platte Co, Mo.				
5	41-Olathe	AC Distribution	161.00	13.00	
6	Olathe-Martin City Rd, Johnson Co, Ks.				
7	42-Brunswick	AC Transmission	161.00	34.00	13.00
8	U.S. Hwy 24, Chariton Co, Mo.	AC Distribution	34.00	13.00	
9	44-Chouteau	AC Distribution	161.00	13.00	
10	1400 Chouteau, Jackson Co, Mo.				
11	46-South Ottawa	AC Transmission	161.00	34.00	
12	N. I-35 & W. U.S.-59, Franklin Co, Ks.	AC Distribution	34.00	13.00	
13	47-Overland Park	AC Distribution	161.00	13.00	
14	9521 W. 88th St, Johnson Co, Ks.				
15	48-Tomahawk	AC Distribution	161.00	13.00	
16	910 W. 103rd St, Jackson Co, Mo.				
17	49-Weatherby	AC Distribution	161.00	13.00	
18	45 Hwy & Garden Rd, Platte Co, Mo.				
19	50-Kenilworth	AC Distribution	161.00	13.00	
20	4601 W. 90th Terr, Johnson Co, Ks.				
21	51-Cedar Creek	AC Distribution	161.00	13.00	
22	K-7 & K-10 Highways, Johnson Co, Ks.				
23	52-Claycomo	AC Distribution	161.00	13.00	
24	Ravena Rd, E. U.S.-69, Clay Co, Mo.				
25	53-Blue Valley	AC Distribution	161.00	13.00	
26	7801 U.S.-24, Jackson Co, Mo.				
27	55-Paola	AC Transmission	161.00	34.00	
28	U.S.-169, Miami Co, Ks.				
29	56-Hickman	AC Distribution	161.00	13.00	
30	11500 Grandview Rd, Jackson Co, Mo.				
31	57-Courtney	AC Distribution	69.00	13.00	
32	Barry & Baker Rd, Jackson Co, Mo.				
33	61-Leeds	AC Distribution	161.00	13.00	
34	4210 Raytown Rd, Jackson Co, Mo.				
35	63-Line Creek	AC Distribution	161.00	13.00	
36	3810 N.W. 64th St, Platte Co, Mo.				
37	65-Antioch	AC Distribution	161.00	13.00	
38	9608 W. 167th St, Johnson Co, Ks.				
39	66-Martin City	AC Distribution	161.00	13.00	
40	13701 Wyandotte, Jackson Co, Mo.				

SUBSTATIONS

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 4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	67-Lakeview	AC Distribution	34.00	13.00	
2	1/4 Mi S of Louisburg on Metcalf, Miami Co, Ks.				
3	68-Roeland Park	AC Distribution	161.00	13.00	
4	4702 Roe Blvd, Johnson Co, Ks.				
5	69-Moonlight	AC Distribution	161.00	13.00	
6	17508 Moonlight Rd, Johnson Co, Ks.				
7	70-Shoal Creek	AC Distribution	161.00	13.00	
8	8500 N Brighton, North KC, Clay Co, Mo.				
9	71-Randolph	AC Distribution	161.00	13.00	
10	Birmingham & Eldon Rds, Clay Co, Mo.				
11	72-Craig	AC Transmission	345.00	161.00	13.00
12	10859 Woodland Rd, Johnson Co, Ks.				
13	73-Centennial	AC Distribution	161.00	13.00	
14	Popular Ridge Rd, Miami Co, Ks.				
15	74-Northeast GSU - Units 11-18	AC Transmission	13.00	161.00	
16	2000 River Front Rd, Jackson Co, Mo.	AC Distribution	161.00	13.00	
17	75-Midtown	AC Distribution	161.00	13.00	
18	1223 E. 48th St, Jackson Co, Mo.				
19	78-Gladstone	AC Distribution	161.00	13.00	
20	2101 E. 72nd St North, Clay Co, Mo.				
21	79-Blue Mills	AC Distribution	161.00	69.00	13.00
22	Atherton & Courtney Rds, Ja Co, Mo.				
23	81-West Gardner	AC Transmission	345.00	161.00	13.00
24	18827 Dillie Rd, Johnson Co, Ks.	AC Transmission	161.00	34.00	
25	82-Murlen	AC Distribution	161.00	13.00	
26	15900 W. 159th St, Johnson Co, Ks.				
27	83-Salisbury	AC Transmission	161.00	34.00	13.00
28	U.S.-24 & Mo.Hwy-5, Chariton Co, Mo.				
29	84-Bunker Ridge	AC Distribution	161.00	13.00	
30	10001 Marion Park Dr, Jackson Co, Mo.				
31	86-Blue Springs	AC Distribution	69.00	13.00	
32	Mo.Hwy-7 & Truman Rd, Jackson Co, Mo.				
33	90-College	AC Distribution	161.00	13.00	
34	16300 W. 110th St, Johnson Co, Ks.				
35	91-Merriam	AC Distribution	161.00	13.00	
36	6412 Carter St, Johnson Co, Ks.				
37	93-Greenwood	AC Distribution	161.00	13.00	
38	65th & Lackman Rd, Johnson Co, Ks.				
39	94-North Kansas City	AC Distribution	161.00	13.00	
40	840 Swift St, Clay Co, Mo.				

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	95-Norton	AC Transmission	161.00	34.00	
2	Missouri Highway-O, Saline Co, Mo.				
3	96-Hawthorn	AC Transmission			
4	8700 Hawthorne Rd, Jackson Co, Mo.				
5	Hawthorn GSU - Unit 5	AC Transmission	21.00	161.00	
6	Hawthorn GSU - Unit 6	AC Transmission	16.00	161.00	
7	Hawthorn GSU - Unit 9	AC Transmission	13.00	161.00	
8	Hawthorn Bank 1	AC Transmission	66.00	13.00	
9	Hawthorn Bank 2 & 32	AC Distribution	161.00	13.00	
10	Hawthorn Bank 11 & 12	AC Transmission	159.00	66.00	
11	Hawthorn Bank 20	AC Transmission	161.00	345.00	13.00
12	Hawthorn Bank 22	AC Transmission	161.00	345.00	13.00
13	98-Riverside	AC Distribution	161.00	13.00	
14	4101 N. Tillison Lane, Platte Co, Mo.				
15	104-Carrollton	AC Transmission	161.00	34.00	
16	N.E. of Carrollton, Carrol Co, Mo.	AC Distribution	34.00	13.00	
17	108-Centerville	AC Transmission	161.00	34.00	
18	W. of Centerville, Linn Co, Ks.				
19	112-Montrose Station GSU - Units 1, 2 & 3	AC Transmission	22.00	161.00	
20	Montrose Station, Henry Co, Mo.				
21	113-Wagstaff	AC Transmission	161.00	34.00	
22	247th St, W. of 69 Hwy, Miami Co, Ks.				
23	114-Lackman	AC Distribution	161.00	13.00	
24	19407 Lackman Rd, Johnson Co, Ks.				
25	115-Redel	AC Distribution	161.00	13.00	
26	4409 W 159th St. Johnson Co, Ks.				
27	117-Bucyrus	AC Distribution	161.00	13.00	
28	21801 Antioch Road, Miami Co, Ks				
29	118-Duncan	AC Transmission	161.00	69.00	
30	2200 N.E. Duncan Rd, Jackson Co, Mo.	AC Distribution	161.00	13.00	
31	121-North Louisburg	AC Distribution	161.00	13.00	
32	N. of Louisburg, Miami Co, Ks.				
33	125-Pflumm	AC Distribution	161.00	13.00	
34	Pflumm & Marshall Dr, Johnson Co, Ks.				
35	127-South Waverly	AC Transmission	161.00	69.00	
36	S. of Waverly, Lafayette Co, Mo.	AC Transmission	161.00	34.00	
37	128-Quarry	AC Distribution	161.00	13.00	
38	24651 W. Hwy 56, Johnson Co, Ks.				
39	132-Cedar Niles	AC Distribution	161.00	13.00	
40	22046 Cedar Niles Rd, Miami Co, Ks.				

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	136-Malta Bend	AC Distribution	161.00	13.00	
2	65 & 127 Hwy, Saline Co, Mo.				
3	137-Pleasant Valley	AC Transmission	161.00	34.00	
4	N. of 68 Hwy, Miami Co, Ks.				
5	472-Baldwin	AC Distribution	34.00	13.00	
6	S. of Baldwin, Douglas Co, Ks.				
7	474-Lynn Valley	AC Distribution	34.00	13.00	
8	N. of K-152 & 69 Hwy, Linn Co, Ks.				
9	478-Michigan Valley	AC Distribution	34.00	13.00	
10	S. of Michigan Valley, Osage Co, Ks.				
11	482-Chiles	AC Distribution	34.00	13.00	
12	69 Hwy & Cleveland-Chiles Rd, Mi. Co, Ks.				
13	484-Walmart	AC Distribution	34.00	13.00	
14	E. of I-35 on K-68, Franklin Co, Ks.				
15	652-LaCygne Lake	AC Transmission	69.00	34.00	
16	E. 220 Rd & Young Rd, Linn Co, Ks.				
17	704-La Cygne GSU - Unit 1 & 2	AC Transmission	22.00	345.00	
18	East side of LaCygne Station, Linn Co, Ks.	AC Transmission	345.00	69.00	
19	705-Iatan GSU - Unit 1	AC Transmission	22.00	345.00	
20	Iatan Station, Platte Co, Mo.				
21	705-Iatan GSU - Unit 2	AC Transmission	25.00	345.00	
22	Iatan Station, Platte Co, Mo.		345.00	161.00	
23	706-Wolf Creek GSU	AC Transmission	25.00	345.00	
24	Wolf Creek Station, Coffey Co, Ks.				
25	707-Levee GSU - Units 7 & 8	AC Transmission	13.00	161.00	
26	Hawthorn Station, Jackson Co, Mo.				
27	708-Bull Creek GSU - Units 1, 2, 3 & 4	AC Transmission	13.00	161.00	
28	18827 Dillie Rd, Gardner, Johnson Co, Ks.				
29	709-Osawatomie GSU - Unit 1	AC Transmission	13.00	161.00	
30	32808 Lone Star Rd, Miami Co, Ks.				
31	716-Spearville Windfarm GSU - Units 1-99	AC Transmission	0.58	34.00	
32	Spearville, Ford Co, Ks.	AC Transmission	34.00	230.00	
33	915-Grand Avenue	AC Distribution	161.00	13.00	
34	115 Grand Ave, Jackson Co, Mo.				
35	292-Liberty South (MOPUB Owned Sub)	AC Transmission	161.00	69.00	
36	2000 Birmingham Rd, Liberty, Clay Co, Mo.				
37	40-Small Company-Owned Substations	AC Distribution			
38	with less than 10 MVA capacity.				
39					
40	133 -Total Company-Owned Substations		15180.58	6047.00	104.00

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	25 Transmission Substations	AC Transmission			
2	108 Distribution Substations	AC Distribution			
3					
4					
5					
6					
7	Notes:				
8	1. All Substations are unattended unless				
9	otherwise specified by an * in column (i)				
10	2. Voltage is in KV (Kilo-Volts)				
11	3. Capacity is in MVA (Mega-Volt-Amps)				
12	4. Ten Transmission Substations include				
13	Generator Step-Up Transformers = GSU				
14	5. Company Owned (CO) Single Customer				
15	Substations are not included.				
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
20	1					1
						2
60	2					3
						4
200	4					5
						6
50	2					7
						8
50	1					9
						10
1100	2					11
33	1					12
33	1					13
						14
174	5					15
						16
67	2					17
						18
127	4					19
						20
158	5					21
						22
200	4					23
						24
19	2					25
						26
184	4					27
						28
20	2					29
						30
134	3					31
						32
60	2					33
						34
136	3					35
						36
113	3					37
						38
97	3					39
						40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
101	3					1
						2
92	3					3
						4
201	5					5
						6
17	1					7
8	1					8
33	1					9
						10
97	3	1				11
14	2					12
85	3					13
						14
114	3					15
						16
130	3					17
						18
206	4					19
						20
67	2					21
						22
180	4					23
						24
250	4	1				25
						26
67	2	2				27
						28
113	3					29
						30
17	3					31
						32
150	3					33
						34
94	3					35
						36
67	2					37
						38
94	3					39
						40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
19	2					1
						2
134	3					3
						4
60	2					5
						6
67	2					7
						8
64	2					9
						10
1500	3					11
						12
64	2					13
						14
507	4					15
185	5					16
192	4	1				17
						18
150	3	1				19
						20
100	2					21
						22
600	1	1				23
25	1					24
93	3					25
						26
37	2					27
						28
45	2					29
						30
10	3	1				31
						32
134	4					33
						34
150	3					35
						36
97	3					37
						38
110	3					39
						40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
17	1					1
						2
						3
						4
650	1	1				5
200	1					6
147	1					7
80	1					8
160	2					9
60	2					10
500	1					11
550	1					12
50	2					13
						14
67	2	1				15
4	1					16
50	2					17
						18
625	3	1				19
						20
25	1					21
						22
34	1					23
						24
64	2					25
						26
67	2					27
						28
60	1					29
30	1					30
33	1					31
						32
67	2					33
						34
20	1					35
25	1					36
67	2					37
						38
34	1					39
						40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
80	1					1
						2
30	1					3
						4
13	2	1				5
						6
19	2	1				7
						8
17	2					9
						10
19	2					11
						12
15	2					13
						14
30	1					15
						16
1820	2	2				17
30	3	1				18
724	1					19
						20
1110	3	1				21
650	1					22
1245	3					23
						24
200	2					25
						26
400	4					27
						28
100	1					29
						30
173	99	1				31
305	2					32
160	2					33
						34
60	1					35
						36
207	87	21				37
						38
						39
20668	437	39				40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
13903						1
6765						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Name of Respondent Kansas City Power & Light Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Schedule Page: 426.2 Line No.: 15 Column: a

This line item includes GSU transformers.

Schedule Page: 426.3 Line No.: 5 Column: a

This line item includes GSU transformers.

Schedule Page: 426.3 Line No.: 6 Column: a

This line item includes GSU transformers.

Schedule Page: 426.3 Line No.: 7 Column: a

This line item includes GSU transformers.

Schedule Page: 426.3 Line No.: 19 Column: a

This line item includes GSU transformers.

Schedule Page: 426.4 Line No.: 17 Column: a

This line item includes GSU transformers.

Schedule Page: 426.4 Line No.: 17 Column: f

This line item includes GSU transformers.

Schedule Page: 426.4 Line No.: 19 Column: a

Footnote Linked. See note on 426.4, Row: 17, col/item:

Schedule Page: 426.4 Line No.: 19 Column: f

This line item includes GSU transformers.

Schedule Page: 426.4 Line No.: 23 Column: a

Footnote Linked. See note on 426.4, Row: 19, col/item:

Schedule Page: 426.4 Line No.: 23 Column: f

This line item includes GSU transformers.

Schedule Page: 426.4 Line No.: 25 Column: a

Footnote Linked. See note on 426.4, Row: 23, col/item:

Schedule Page: 426.4 Line No.: 27 Column: a

This line item includes GSU transformers.

Schedule Page: 426.4 Line No.: 29 Column: a

This line item includes GSU transformers.

Schedule Page: 426.4 Line No.: 31 Column: a

This line item includes GSU transformers.

Schedule Page: 426.5 Line No.: 1 Column: a

Transmission Substations with Generator Step-Up Transformers have "GSU" indicated on the individual line items.

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is \$250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	Non-power Goods or Services Provided by Affiliated			
2	Construction work in process	GMO	107	765,034
3	Common use facilities, networks and phones	GMO	922	3,035,933
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	Non-power Goods or Services Provided for Affiliate			
21	Non-utility operations	GPE	817.1	399,919
22	Construction work in progress	GMO	107	24,470,589
23	Retirements	GMO	108	4,444,932
24	Undistributed stores expense	GMO	163	2,512,495
25	Deferred customer program expenses	GMO	182	459,901
26	Fleet, overhead and tool clearings	GMO	184	10,598,869
27	Payroll taxes	GMO	408	5,179,496
28	Community service and donations	GMO	426.1	909,023
29	Lobbying	GMO	426.4	195,959
30	Generation supervision & engineering	GMO	500	2,131,304
31	Fuel	GMO	501	3,613,561
32	Steam expense	GMO	502	4,855,099
33	Electric expense	GMO	505	1,751,558
34	Miscellaneous steam power	GMO	506	1,789,440
35	Generation maintenance supervision & engineering	GMO	510	1,757,615
36	Maintenance of structures	GMO	511	914,867
37	Maintenance of boiler plant	GMO	512	3,269,551
38	Maintenance of electric plant	GMO	513	802,487
39	Generation expenses	GMO	548	694,931
40	Other power supply maintenance supervision & eng.	GMO	551	278,079
41	Maintenance of generating & electric equipment	GMO	553	972,488
42	System control and load dispatching	GMO	556	1,165,942
1	Non-power Goods or Services Provided by Affiliated			
2				

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is \$250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	Non-power Goods or Services Provided for Affiliate			
21	Other power supply expenses	GMO	557	2,614,610
22	Transmission supervision & engineering	GMO	560	1,064,963
23	Transmission load dispatching	GMO	561	528,591
24	Transmission expense	GMO	566	934,203
25	Transmission maintenance	GMO	570	534,704
26	Distribution supervision & engineering	GMO	580	3,885,836
27	Distribution load dispatching	GMO	581	712,911
28	Overhead line expense	GMO	583	1,215,427
29	Underground line expense	GMO	584	690,946
30	Meter expense	GMO	586	2,053,867
31	Distribution expense	GMO	588	5,822,885
32	Maintenance of distribution structures	GMO	591	305,616
33	Maintenance of station equipment	GMO	592	340,763
34	Maintenance of overhead lines	GMO	593	1,951,817
35	Maintenance of underground lines	GMO	594	558,744
36	Maintenance of line transformers	GMO	595	334,563
37	Maintenance of street lighting & signals	GMO	596	287,457
38	Maintenance of misc. distribution plant	GMO	598	332,800
39	Customer accounts supervision	GMO	901	627,931
40	Meter reading	GMO	902	1,861,769
41	Customer records and collections	GMO	903	5,490,265
42	Misc customer account expense	GMO	905	275,307
1	Non-power Goods or Services Provided by Affiliated			
2				
3				
4				

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is \$250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	Non-power Goods or Services Provided for Affiliate			
21	Customer service	GMO	910	985,617
22	Sales expense	GMO	912	329,105
23	Administrative and general salaries	GMO	920	14,754,318
24	Office supplies and expenses	GMO	921	1,736,609
25	Common use facilities, networks & phones	GMO	922	8,540,261
26	Outside services	GMO	923	2,211,034
27	Property insurance	GMO	924	1,338,096
28	Injuries and damages	GMO	925	1,864,026
29	Employee benefits	GMO	926	7,165,863
30	Regulatory expense	GMO	928	1,216,410
31	Miscellaneous general expenses	GMO	930	1,201,963
32	Rents	GMO	931	2,334,081
33	General plant maintenance	GMO	935	1,737,138
34				
35				
36				
37				
38				
39				
40				
41				
42				

Name of Respondent Kansas City Power & Light Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Schedule Page: 429 Line No.: 2 Column:

Note applies to lines 1-42:

Affiliate transactions for goods and services are billed at cost with the cost captured and billed based on the project code. Goods and services related to one affiliate are direct billed based on the owner of the project charged. When a good or service relates to more than one affiliate, the cost is allocated to affiliates on a relevant cost driver determined by the type of cost and the benefiting affiliate.

Assets belonging to KCP&L may be used by another affiliate. The billing for common use property is based on the depreciation or amortization expense of the underlying asset and a rate of return applied to the net plant. The total cost is then allocated on an applicable allocation factor.

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